Edwardsport Integrated Gasification Combined Cycle Power Station

Front End Engineering and Design Study Report

The December 13, 2006, Prehearing Conference Order of the Indiana Utility Regulatory Commission ("Commission") in Cause No. 43114 provided for Duke Energy Indiana, Inc. ("Duke Energy Indiana") and Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren"), as Joint Petitioners, to file their Front End Engineering and Design ("FEED") Study for the integrated gasification combined cycle ("IGCC") project at Duke Energy Indiana's Edwardsport Generating Station ("Project" or "Edwardsport Project") on or before April 2, 2007. This report of the FEED Study ("Report") summarizes the results of thousands of pages of engineering drawings, calculations, and analyses produced as a part of the Edwardsport IGCC FEED Study. These details are available to the Commission and the parties to this proceeding, subject to appropriate protection of proprietary confidential information.

EXECUTIVE SUMMARY

The primary purpose of the FEED Study was to examine IGCC technology as a potential base load electric generating option for the Duke Energy Indiana system and to develop the required information to produce a more definitive cost basis for the Project, a Project execution schedule and performance characteristics for the Project, together with a revised Project Scope Book, which will serve as the technical specifications for the Project. The Table of Contents of the Project Scope Book is attached as Exhibit A. The Project Scope Book consists of eight large binders and is available for review upon request by the parties to Cause No. 43114 and to the Commission, subject to appropriate confidentiality protection. Although some additional work remains, we have reached the following conclusions:

- The Project is technically feasible and commercially reasonable. The IGCC technology developed to meet Duke Energy Indiana objectives under the GE/Bechtel Alliance[1] work performed in association with this study represents a product that will deliver 630 megawatts of reliable

[1] Any reference to the "GE Bechtel IGCC Alliance" or the "Alliance" is a reference to the business arrangement established between the General Electric Company, by and through its GE Energy business, and Bechtel Corporation pursuant to the terms of the Alliance Agreement entered into between the parties, and does not signify a joint venture, partnership or any separate legal entity.

power with superior environmental performance at a thermal efficiency equal to or better than supercritical pulverized coal technology.

- As expected, the IGCC process carries a capital cost premium over other technologies. The recent run-up in commodity pricing and competition for engineered products and labor has caused an increase in the estimated Project cost. The expected cost of the Project is approximately $1.985 billion, including future escalation of 4% per year. This represents a capital cost approximately 5.2% higher than the high range of Duke Energy Indiana's capital cost estimate included in Joint Petitioners' October 2006 pre-filed testimony. This estimate is within the cost estimate range referenced in Joint Petitioners' pre-filed testimony based on an Electric Power Research Institute estimate for a similarly sized IGCC plant. Duke Energy Indiana believes that the escalating material and labor costs included in this more definitive estimate will also impact other power plant technologies.

- The Feasibility Study estimated that the cost of an IGCC plant would be 10% to 15% higher than a conventional pulverized coal project. In order to decrease the IGCC lifecycle cost, Duke Energy Indiana successfully worked with state and local governmental entities to develop financial incentives for the Project (currently estimated at over $300 million) and also applied for Federal tax incentives available under Section 48A of the Energy Policy Act of 2005. The Edwardsport Project was one of two projects nationwide to be awarded a $133.5 million Federal investment tax credit provided that the Project is constructed within the required time frame. The value of the local, state and federal incentives is not taken into account in the cost estimates included in this Report.

- The FEED Study provided a detailed level 3 Project schedule. This schedule provides a substantial completion date 47 months after full notice to proceed. It is very important to both Vectren and Duke Energy Indiana that this Project attain commercial operation to support summer 2011 base load needs. However, the current schedule assumes a full notice to proceed on November 1, 2007 with a projected commercial operation date ("COD") of October 2011. The Alliance has provided an alternate schedule that pulls the power block activities forward in the schedule and expedites engineering if the appropriate vendor information can be provided. Duke Energy Indiana will attempt to obtain the required information by working with GE and targeted vendors to develop the data with a minimum of capital investment. The earlier schedule is aggressive and relies heavily on the availability of this vendor data and assumptions identified on the alternate schedule. The milestone schedules are attached as Exhibits B-1 and B-2.

- The Edwardsport Project will be carbon capture ready. The general site arrangement will include space for future carbon capture equipment. However, no additional gasification plant capacity has been added to the design to account for future derating of the plant capacity when carbon capture is required.

- A lump sum turn key contract approach is not the best option or even a viable option for this Project. Price and labor volatility, together with the uncertainty around the full notice to proceed date require extraordinary contingency amounts to be added to the price by any general contractor that would offer a lump sum turn key price, including GE and Bechtel. The contract approach upon which the FEED Study Project cost is estimated represents a blend of cost reimbursable, target cost, and lump sum pricing, with Duke Energy Indiana managing the Project, similar to Duke Energy Indiana's contracting approach on other major construction projects.

DESCRIPTION OF THE FEED STUDY PROJECT

Although the Edwardsport IGCC Feasibility Study in 2005 determined that there were no "fatal flaws" to constructing and operating an IGCC plant at the Edwardsport site, additional information was required to develop more definitive cost, schedule and performance estimates in order to determine whether it would be reasonable to continue with the Edwardsport Project. Due to the successful but limited nature of commercial experience with IGCC technology, considerable front end engineering was required in order to assess the cost and capabilities of an IGCC plant located at the Edwardsport site. Duke Energy Indiana selected the General Electric Company ("GE")/ Bechtel Corporation ("Bechtel") Alliance ("Alliance") to perform engineering services required to develop this information using the GE Gasification technology. Duke Energy Indiana also arranged for additional services by various agencies, consultants and suppliers in order to provide site specific data required by the Alliance and required by Duke Energy Indiana for the portions of the Project beyond the scope of the Alliance. Duke Energy Indiana managed the activities comprising the overall FEED Study using 11 full time and over 15 part time employees contributing approximately 30,000 man-hours to the Project. In addition to in-house expertise, Duke Energy Indiana retained MPR and Associates and Energy Resource Consultancy International LLC to provide "Owner's Engineer" services to assist with evaluation of chemical process engineering and gasification technology issues. Vectren shared a portion of the study costs and has an option for a 20% joint ownership should the Project be approved and constructed.

Time is important to Duke Energy Indiana and Vectren, as additional capacity is needed by 2011. Because of the need for commercial operation by Summer 2011, applications for the air permit and Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") interconnection were developed using preliminary data, which will be updated as appropriate. Duke Energy Indiana has also obtained voluntary purchase option agreements from land owners adjacent to the current Edwardsport Generating Station for the necessary land to construct the Project.

The FEED Study work consisted of three specific areas of focus performed by Duke Energy Indiana, GE and Bechtel. First, in addition to managing the study, Duke Energy Indiana performed evaluation work involving the Edwardsport site, such as basic utilities development, and estimating the cost of work to be performed or provided by the Project owner(s). Second, GE, as the technology owner, developed the base reference design using input from Duke Energy Indiana and other customers working on similar projects. Third, starting with the base design, including a process design package and estimated plant performance parameters, Bechtel produced high to mid-level engineering drawings, calculations and evaluations from which to estimate the cost of the Project. This Report provides information on the scope of work conducted by all three companies, beginning with Duke Energy Indiana.

DUKE ENERGY INDIANA SCOPE

UNDERGROUND MINE MITIGATION - Duke Energy Indiana has long been aware of old underground mining in the Edwardsport vicinity. Duke Energy Indiana retained GAI Consultants ("GAI") to perform an evaluation of the underground mine area using underground radar and electronic imaging techniques to verify the location and depth of the mine workings. GAI determined that the mined areas can be sufficiently mitigated to allow construction of the IGCC plant over the mine areas. GAI has provided estimated costs, quantities of fill material, methods for placement and is currently preparing specifications for performing the mine grouting work.

GAS LINE INVESTIGATION - The IGCC plant will require a supply of natural gas for startup and to provide a backup fuel source. This line will connect with Midwestern Gas Transmission Company approximately five miles from the Edwardsport site. Using data developed during the FEED Study Vectren has provided a cost estimate for the gas line and required pressure reduction and metering station equipments.

LAND FILL SITING STUDY - ATC Associates performed a land fill siting study to determine a suitable site that can be developed in the event that disposal of significant out-of-specification slag material becomes necessary. A land fill is not expected to be required and no cost for such development is included in the Project cost estimate.

SOIL BORING AND GEOTECHNICAL EVALUATION- Duke Energy Indiana retained Banning Engineering and Patriot Engineering to conduct a combination of surveying and soil boring analyses to obtain information necessary for Bechtel to develop the geotechnical report. This report will be the basis for foundation design in specific areas where equipment will be located.

RAIL TRANSPORTATION STUDY - Burns & McDonnell Engineers performed a rail corridor study to identify several potential rail routes into the site, ranging from about five miles to about eighteen miles in length. Although no specific corridor has been selected, the Project estimate includes an allowance for a rail line to be constructed. The rail line must be installed prior to the 1st quarter 2009 if it is to be used to offset equipment transportation cost and enable larger pieces of shop fabricated equipment to be delivered to the Project site. In order to meet this date, engineering work on the rail project needs to begin in mid-2007, with construction of the rail line beginning in early 2008. A public meeting will be held to receive input before a final route is selected.

TRAFFIC STUDY - A traffic study was performed by Hawkins Environmental-Butler, Fairman, and Suefert to determine the impact of truck traffic entering and leaving the Project site. No significant additions were identified as necessary; however, the Project cost estimate includes an allowance for installation of breakdown and turn lanes that may be required.

CLASS 1 WASTE WATER INJECTION WELL - The Alliance reference design contains a large waste water treatment facility with provisions for zero liquid discharge from the site. This system represented a high capital cost (over $50 million), reduced power output from the Project and would have created ongoing operating and maintenance expenses. Duke Energy Indiana retained Subsurface Group, Inc. of South Bend, Indiana to perform an evaluation of a class 1 injection well system to dispose of high chloride water. As a result of the study, the Alliance wastewater treatment system has been scaled back to include pre-injection filtration processing only. The cost of an injection well system for wastewater disposal is included in the estimated cost of the Edwardsport Project, but not in the Alliance scope of work. A test well will be completed early in the Project to confirm the use of this disposal method. This process is essentially the same method used at the Duke Energy Indiana Gibson Station for disposal of high chloride water from the scrubber process. The saline aquifer into which the water is to be injected has a chloride content of 250,000 parts per million versus the injection water which has a chloride content of approximately 4000 ppm.

CARBON SEQUESTRATION FEASIBILITY STUDY - The Indiana Geological Survey performed a feasibility study of the Edwardsport site to assess the potential for carbon sequestration. The study identified several potential storage areas. Duke Energy Indiana purchased two-dimensional seismic data from commercial sources, permitting enhanced investigation by the Indiana Geological Survey, confirming that the site continues to appear feasible for long term storage of carbon dioxide. The next steps for additional investigation are to perform additional seismic testing and eventually drill a test well to identify specific injection zones for test injection. This work is not scheduled at this time, nor is it included in the Project cost estimate.

ARCHAEOLOGICAL STUDY - An unexpected archaeological find on site during construction can significantly impact Project progress. As a precautionary measure, Duke Energy Indiana retained the services of Natural and Ethical Environmental Solutions to perform level 1 archaeology assessments at the Edwardsport site. These assessments yielded no significant findings.

FUEL SUPPLY STUDY AND EVALUATION - Fuel specification is a critical design parameter for an IGCC plant and must be developed early in the design process. Several major systems are affected by specific fuel parameters. Duke Energy Indiana utilized our in-house geologist and fuel procurement specialists to assist in developing the initial coal specification. At their recommendation, Duke Energy Indiana retained Skelly and Loy Engineering-Environmental Consultants to perform two studies that began in October 2005 and concluded in May 2006. The first study looked at the availability of coal and its proximity to the Project site. Results of this study yielded a conservative estimate of 170 million tons of recoverable Indiana #5 seam coal in the State of Indiana that meets the design criteria of the plant. The second study involved taking core drill samples of potential coal reserves combined with available reserve data from mine owners to verify that the fuel specification design range for the Edwardsport Project is compatible with these reserves. The results of this study provided the necessary verification to ensure fuel availability well beyond the design life of the facility.

COAL HANDLING SYSTEM STUDY - The coal handling system evaluation and pricing estimate did not require a significant interaction with the process design; therefore, Duke Energy Indiana chose to develop the cost estimate for this portion of the Project outside the scope of the Alliance FEED Study. Duke Energy Indiana retained Roberts and Schaefer Company, a material handling supplier for development of the base system design and estimated cost. This cost is included in the Project cost estimate.

COLLECTOR WELL STUDY -To verify an adequate water supply for the plant, Duke Energy Indiana retained Collector Well International, Inc. to perform a feasibility study on supplying make-up water via radial collector wells. This study began in December 2005 and progressed through three phases of drilling, pumping, and monitoring of the local underground aquifer. The study, concluded in May 2006, indicated that two collector wells will provide sufficient make-up water supply to meet the demands of the facility, even under poor conditions such as low water temperature in the aquifer in conjunction with low water levels in the White River. The installation of collector wells was weighed against a refurbishment of the water intake structure for the existing Edwardsport Generating Station and deemed to be the best overall solution. An estimated cost for two wells is included in the Project cost estimate.

MIDWEST ISO STUDIES -The Project will interconnect to the existing Duke Energy Indiana 345kV system that crosses the proposed plant site. The Midwest ISO has coordinated several studies assessing the thermal capability of the transmission system, system stability, and deliverability of the additional generation from the Edwardsport site. The cost estimate for the Project includes an allowance for interconnection costs. As of the date of this Report nothing has come to Duke Energy Indiana's attention that indicates this estimate should be changed.

AIR PERMIT APPLICATION AND STATUS - The air permit application was filed with the Indiana Department of Environmental Management in August 2006 with preliminary data from phase I of the FEED Study. The permit is currently pending an update of data from the FEED Study and potential incorporation of value engineering items, such as site optimization, that are continuing to be evaluated as the Project is developed. Duke Energy Indiana anticipates filing modeling data for the final design in the summer of 2007. This should allow ample time to receive the permit prior to the start of construction.

NPDES PERMIT STUDY - A permit modification to the existing National Pollutant Discharge Elimination System ("NPDES") permit for Edwardsport Station will be required. The existing ash ponds will be converted to settling ponds, with the ability to manage any contamination issues from site runoff water or neutralization waste prior to discharge. The Project estimate contains an allowance for potential modifications to the discharge canal.

OVERVIEW OF THE ALLIANCE/DUKE ENERGY INDIANA FEED STUDY WORK

Execution of the FEED Study involved the full range of technical, commercial and managerial resources of the GE/Bechtel Alliance, working in concert with the Duke Energy Indiana Project team to produce the necessary inputs and analyses. Over 250 professionals from Bechtel and GE were involved in this process over a 13 month period.

The FEED Study was conducted in three distinct phases. In phase I the basic design was reviewed and confirmed to establish the configuration of the process systems and to set the physical layout of the facility. The initial estimates of the thermal performance and emissions profile for the facility were generated based on the phase I design outcome. A key outcome of phase I was development of the engineering documents in support of the application for the air permit. In phase II the basic design was developed further with more detailed engineering drawings and documents, which resulted in the "Issue for Estimate" version of the Piping and Instrument Diagrams (P&IDs). The P&IDs are the cornerstone engineering drawings that set and define the overall design of the facility. Phase II concluded with the completion of the Hazards Identification Study ("HAZID"). The HAZID consisted of a detailed review of the Process Flow Diagrams by the Project team to identify potential process hazards to allow for consideration and possible implementation of process changes, preventive safeguards, and hazard reduction measures into the design. Phase III consisted of conducting a Value Engineering Study and finalizing the FEED Study phase I & II deliverables.

The following summary sets forth a more detailed description of the activities conducted during each phase of the FEED Study.

FEED Study Phase I - Detail

The starting points for the FEED Study were the Project Scope Book developed during the Feasibility Study phase, the IGCC Reference Plant design developed by the Alliance, and the Technical Services Agreement dated February 13, 2006, as amended May 30, 2006 ("TSA"), which is the contract executed between Duke Energy Indiana and the Alliance for conducting the FEED Study.

The Feasibility Study Project Scope Book defined the basis of design of the Duke Energy Indiana Edwardsport Project at a conceptual level. The key engineering documents making up the Project Scope Book were the System Flow Diagrams and associated Heat and Material Balances ("HMBs"). The engineering documents in the Project Scope Book defined the physical layout of the IGCC facility, the sequential order of the process systems and equipment, and the associated flow rates of the main process systems. The indicative estimates of the thermal performance and emissions profile for the facility were also included in the Project Scope Book.

Between the end of the Feasibility Study and the start of the FEED Study the Alliance continued to develop the design of the Reference Plant. The Reference Plant design is a standard product developed by the Alliance for the IGCC market. As a product, the IGCC Reference Plant benefited from the new product introduction work processes that GE applied to assure the Reference Plant product was aligned with utility customer and market requirements. The design processes applied by GE for the Reference Plant followed new product development steps similar to those used across GE for developing large products. The process consisted of conducting surveys of utility customers to identify, rank, and establish the performance requirements for the IGCC Reference Plant. The requirements established were designated as critical to quality parameters. The critical to quality parameters identified consisted of the following: net power generation, capital cost, thermal efficiency, emission profile, and reliability.

The primary purpose of phase I of the FEED Study was to establish the base configuration of the Edwardsport IGCC facility and the associated emissions profile to enable Duke Energy Indiana to develop the air permit application, which was filed with the Indiana Department of Environmental Management. In addition, the preliminary thermal performance calculations for the facility were completed by the Alliance and the results were provided to Duke Energy Indiana. The preliminary performance results were utilized by Duke Energy Indiana in the 2005 Integrated Resource Plan filed with the Commission.

Establishing the base configuration for the Project consisted of reviewing several Reference Plant design alternatives the Alliance had generated between the end of the Feasibility Study and the start of the FEED Study. The Alliance conducted engineering studies and generated recommended process design alternatives to implement for the purpose of improving upon the critical to quality parameters established during the initial development of the Reference Plant product.

The following summary sets forth a brief description of the significant alternatives that were evaluated and selected for implementation during phase I:

- CO_2 Tail Gas Recycle - This engineering study defined the benefits of recycling the CO_2 containing tail gas from the effluent of the Sulfur Recovery Unit back to the gasification process. Tail gas is a waste gas stream containing significant amounts of CO_2 and Sulfur. Typically tail gas is either treated further in a Tail Gas Treating Unit to reduce the Sulfur content and then combusted in a thermal oxidizer, or recycled to the Acid Gas Absorber system for reprocessing. The benefits of recycling the tail gas to the gasification process were identified to be improved thermal efficiency of the facility, reduced gasifier operating temperature, and elimination of the Tail Gas Treating Unit. The identified benefits exceeded the estimated costs associated with installation and operation of additional compression equipment.

- CO_2 Flash Gas Recycle Optimization - This engineering study defined the optimum amount of CO_2 Flash Gas to be recycled to the gasification process island. As the amount of Flash Gas recycle increases, there is an associated increase in auxiliary power consumed to compress the Flash Gas to the required pressure. The outcome of the study was a recommendation to recycle 22% of the CO_2 Flash Gas to the gasification process island and to install Carbonyl Sulfide hydrolysis equipment. The benefits of the hydrolysis equipment are reduced Selexol™ (a trademark of UOP LLC, a Honeywell company) recirculation and reduced sizing of the acid gas treating equipment. The combined benefits from reduced CO_2 Flash Gas Recycle and installation of hydrolysis equipment are reduced auxiliary power consumption and reduced capital cost.

- <u>Low Temperature Gas Cooling Train Optimization</u> - This engineering study was conducted to determine if a dedicated Low Temperature Gas Cooling ("LTGC") section for each Gasifier was more optimal than the Reference Plant configuration in which a single LTGC section served both Gasification sections. The recommendations from the study were to apply a dedicated LTGC section for each Gasification section and to also install an Acid Gas Absorber dedicated to each LTGC section. The overriding benefits of the dedicated LTGC and Acid Gas Absorber for each Gasifier train are reduced emissions during start-up operations, elimination of the need for a low sulfur start-up fuel such as methanol, reduced operating and maintenance costs, increased operational flexibility, and increased reliability.

- <u>Syngas Versus Diluent Nitrogen Saturation</u> - The purpose of this engineering study was to optimize the addition of mass flow (through the addition of water) into the gas turbine combustion system via comparison of saturation of the diluent nitrogen or via saturation of the syngas fuel. Increasing the mass flow into the gas turbine combustion system results in the ability to generate additional electric power up to the physical limits of the combustion turbine generator. The recommendation from the study was to implement saturation of the syngas fuel. Application of syngas saturation is expected to have the following impacts on the Edwardsport IGCC facility: reduction in capital cost, increase in power output, increase in thermal efficiency, and improved operability due to reduction in complexity.

- <u>Acid Gas Removal Optimization</u> - This study consisted of evaluating the application of solvent refrigeration as compared to a non-refrigerated solvent configuration. The starting basis for the study was application of solvent refrigeration. Increasing the hydrogen sulfide concentration in the acid gas stream, through refrigeration of the solvent, results in a more efficient removal of sulfur in the Sulfur Recovery Unit. The recommendation from the study confirmed that application of solvent refrigeration resulted in a reduction in the total installed cost of the facility primarily as a result of the predicted increase in net power generation from the facility and an increase in thermal efficiency.

- Sulfur Recovery Unit Design Optimization (2 vs. 3 Catalytic Reactor Stages) - The objective of this study was to determine whether the Sulfur Recovery Unit catalytic reactors should be configured with two stages or three. The starting basis for the study was application of three stage catalytic reactors. The catalytic reactor is the device that converts sulfur compounds in the acid gas to elemental sulfur, which, in turn, is condensed and recovered as a useful byproduct. The study determined that application of two-stage catalytic reactors would result in a reduction in the capital cost of the facility with minimal impact on the other critical quality parameters.

Duke Energy Indiana selected each of the recommended alternatives. Accepting the Reference Plant alternatives as the basis for the Duke Energy Indiana facility aligned the Duke Energy Indiana design with the Reference Plant design at the conclusion of FEED Study phase I.

A second key activity during FEED Study phase I is that Duke Energy Indiana commissioned the Alliance to conduct the following engineering studies in support of further optimization of the Reference Plant design for the Edwardsport Project:

- Low Pressure Absorber - Upon receiving the emissions profile data for the Edwardsport Project from the Alliance, Duke Energy Indiana conducted air dispersion modeling. As a result of the dispersion modeling Duke Energy Indiana determined the sulfur emissions that evolved during start-up and emergency trip operations resulted in ground level sulfur concentrations that exceeded National Air Quality Standards threshold requirements. Duke Energy Indiana submitted this information to the Alliance and asked the Alliance to develop a process modification to reduce the sulfur emissions during start-up and emergency trip operations. The solution identified by the Alliance Reference Plant emissions team was to install a Low Pressure Absorber in the Acid Gas Removal section that will process the acid gas during start-up and emergency trip conditions. The Low Pressure Absorber system was included in the design during phase I activities.

- Reduction of Carbon Content in Effluent Slag - One of the design goals is to be able to utilize the slag generated by the gasification process in a beneficial manner. Slag produced by the base gasification design, is expected to be a suitable fill material for construction or general grade change and road base aggregate. During FEED Study phase I Duke Energy Indiana commissioned the Alliance to conduct a study to identify the process changes necessary to reduce the carbon content of the slag to less than 3.5% to enable the slag to potentially be sold for other commercial applications, such as roofing grit, blocks and other bulk product markets. The Alliance completed the study during FEED Study phase II with identification of process changes consisting of a floatation system that would be capable of reducing the carbon content of the slag to less then 1%. At this level of carbon content, the slag material becomes more valuable and can be used for such items as lightweight structural concrete, roof tiles, insulating concrete, filtration media and undefined agricultural uses. Duke Energy Indiana will decide whether or not to implement the floatation system into the design during detail engineering, based on further investigation and an economic evaluation of potential slag markets.

- Addition of a CO Catalyst in the Heat Recovery Steam Generator - Duke Energy Indiana anticipates that in the future the emission threshold requirement for CO may be reduced. Duke Energy Indiana commissioned the Alliance to conduct a conceptual evaluation to determine the cost and potential impact of installing a CO Catalyst module in the Heat Recovery Steam Generators ("HRSGs"). The result of the study indicated installation of CO Catalyst modules would reduce the thermal efficiency of the facility while increasing the capital cost. Duke Energy Indiana decided not to include installation of CO Catalyst modules, due to the negative impacts on plant performance as well avoidance of any risk due to CO Catalyst systems not being proven in syngas fired gas turbine systems. Duke Energy Indiana did decide to design the HRSGs with an open duct area in a suitable location for potential future installation of CO Catalyst modules.

- Elimination of the Zero Liquid Discharge System - The Reference Plant Zero Liquid Discharge System option is energy and capital intensive. Based on previous engineering work by Duke Energy Indiana for the Gibson Generating Station Duke Energy Indiana knew there was a potential to process the wastewater stream generated by the gasification process in a less energy intensive and less costly manner that is environmentally acceptable. During FEED Study phase I Duke Energy Indiana instructed the Alliance to expedite the determination of the composition of the gasification wastewater stream. Upon receipt of the composition, then Duke Energy Indiana conducted an evaluation to determine the feasibility of disposing of the wastewater via Deep Well Injection, as described previously in this Report. The results of the study indicate that Deep Well Injection is a suitable disposal method for the gasification wastewater stream. As a result, the Zero Liquid Discharge System was eliminated from the design and wastewater pre-treatment for deep well injection was added during FEED Study phase II.

- Coal Composition Evaluation (Duke Energy Indiana versus Reference Plant) - During the design evolution of the Reference Plant, the design values for sulfur and chlorine were increased from the values specified in the Feasibility Study. As a part of the FEED Study Duke Energy Indiana needed to determine the potential cost and efficiency impact of applying Indiana coal composition, for the performance and design cases, to the Reference Plant design. Upon completion of the FEED Study it was determined that the Duke Energy Indiana coal composition parameter values for sulfur, ash, moisture, and chlorine were within the specified design coal composition for the Reference Plant. The Alliance has stated that the higher levels of moisture, ash, sulfur and chlorine that are included within the design basis for the Reference Plant and which are also representative of the Indiana coal proposed for the Edwardsport Project, result in additional capital cost and some efficiency reduction when compared to coals such as Pittsburgh #8.

- Application of Selective Catalytic Reduction ("SCR") - During FEED Study phase I Duke Energy Indiana consulted with GE to determine the operational risks of applying SCR technology at the HRSGs to reduce the NO_x emissions from the facility. Although the Reference Plant was designed to be SCR capable, it did not include direct application of SCRs for the Project. The Alliance determined that maintaining the sulfur content in the Syngas to less then 20 parts per million (volume dry basis) would enable application of SCR technology with low risk of operation problems. The expectation is that the low temperature heat transfer surfaces in the HRSG will require cleaning less then one time per year to remove accumulated ammonia sulfate and that catalyst deactivation should not occur. Based in part on this information Duke Energy Indiana decided to include SCRs in the design of the HRSGs for NOx emissions reduction.

- Transportation and Logistics Study - Beginning during phase I and continuing throughout the FEED Study, a Duke Edwardsport IGCC Transportation and Logistics Study was undertaken. Because of its inland location, the transportation of "over-sized" equipment to the Project site was identified as a key area of cost and scheduling risk for the Project that needed to be resolved during the execution of the FEED Study. To identify and resolve any transportation constraints for the over-sized equipment the Alliance conducted the Duke Edwardsport IGCC Transportation and Logistics Study with the assistance of the Indiana Department of Transportation. The over-sized equipment consists of the Radiant Syngas Coolers, Gas Turbine Generators, Steam Turbine Generator, HRSG components, Air Separation Unit (ASU) components, Generator Step Up Transformers, Selexol™* Absorber, Selexol™* Stripper, COS Hydrolysis Reactor, SynGas Saturator Column, LP Absorber, and the Rich Selexol™* Storage Tank. The Study concluded that all of the over-sized equipment can be transported and delivered to the Edwardsport Project site. The transport will require the application of a combination of equipment modularization, on site assembly, and multiple means of transport consisting of barge, rail and over-the-road heavy haul. An equipment transportation plan was developed for the execution phase of the Edwardsport IGCC Project and is incorporated into the estimate.

FEED Study Phase II - Detail

In FEED Study phase II the basic design established during phase I was developed in detail via generation, distribution, and review of the process design engineering drawings and documents. The work process for developing the drawings and documents consisted of the following steps:

- Transmittal to the Duke Energy Indiana Alliance FEED Project team of the Reference Plant drawings and documents from GE's Gasification Process Engineering organization.

- Review and conversion of the Reference Plant drawings and documents, by the Duke Energy Indiana FEED Alliance Project team, to the Duke Energy Indiana Project drawings. This consisted of the Alliance FEED Project team reviewing the drawings to ensure that all process design changes established in phase I were depicted in the drawings and documents, and revising title blocks to the Duke Energy Indiana standard.

- Transmittal of the resulting drawings and documents to the Duke Energy Indiana FEED Project team for the review and comment cycle. The review and comment cycle consisted of several issues of the drawings. The first issue was for review and comment by Duke Energy Indiana personnel. Following the submission of written comments by the Duke

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Energy Indiana Project team to the Alliance, formal review meetings with Alliance and Duke Energy Indiana Project team members were conducted to jointly review the drawings and resolve the submitted comments. Upon completion of the review meetings the drawings were revised as needed and "Issued for Design" or "Issued for Estimate" as appropriate.

The key drawings and documents generated and reviewed during phase II were as follows:

- Heat and Material Balances - Documents defining the composition, flow, temperature, and pressure of the process streams.

- Process Flow Diagrams - Drawings depicting the configuration of the process equipment at a system level.

- Material Selection Guides - Drawings defining the material of construction for the equipment and piping.

- Process Data Sheets - Documents that specify the design process service conditions (material, flow rate, temperature, pressure) for the process equipment.

- Piping and Instrument Diagrams - Detailed drawings depicting the equipment, piping, and control instrumentation. These drawings set and define the overall design of the facility.

- Design Criteria - Documents defining the design criteria applicable to each of the engineering disciplines (Electrical, Mechanical, Civil/Structural /Architectural, Instrument and Controls, and Plant Design).

The generation, review, and finalization of the drawings and documents were conducted over the time period of May to October 2006. There were hundreds of drawings and documents reviewed during this time frame.

Near the end of phase II, the Hazards Identification Study ("HAZID") was conducted. The HAZID consisted of a detailed review of the Process Flow Diagrams by the joint Duke Energy Indiana and Alliance Project team to identify potential process hazards to allow for consideration and possible implementation of process changes, preventive safeguards, and hazard reduction measures into the design. The primary hazard identified was the potential for inadvertent release of gaseous streams that may ignite or result in personnel exposure to a toxic atmosphere. The HAZID Study recommends conducting dispersion modeling of potential gaseous releases to identify the potential for toxic concentrations to evolve at or beyond the property line, and to develop appropriate Hazardous Communications procedures and training processes. The HAZID recommendations will be addressed during the detailed engineering phase of the Project.

Phase II concluded with the completion of the HAZID, and the transmittal to Duke Energy Indiana of the Issue for Estimate version of the Piping and Instrument Diagrams. The Issue for Estimate Piping and Instrument drawings set the basis for the development of the detailed cost estimate which was generated during FEED Study phase III.

FEED Study Phase III - Detail

FEED Study phase III involved conducting the Value Engineering Study and finalizing the FEED Study deliverables, consisting of the Project Scope Book, the detailed cost basis for the Project, and the detailed execution schedule for the Project.

The Value Engineering Study was conducted in an effort to identify ideas that had the potential to significantly reduce the capital cost of the Project. The Alliance retained a consultant that specializes in conducting and facilitating value engineering workshops for large capital intensive projects. The consultant was given access to key Project team members to conduct pre-meeting interviews.

The Value Engineering workshop was conducted over a three day period attended by 26 Project team members representing Duke Energy Indiana, Bechtel, and GE. Hundreds of ideas were generated during the brainstorming sessions. Subsequently, the initial set of ideas were rated, ranked, and sorted such that at the end of the workshop a total of 58 ideas were selected for further evaluation. The 58 ideas from the workshop were then distributed within the GE, Duke Energy Indiana, and Bechtel Project teams for further high level rating and sorting. The combined teams then met together again for the final selection of ideas, which resulted in the selection of 31 ideas for further definition, development, and cost/benefit analyses. The further development of the selected items occurred during the December 2006 through March 2007 timeframe. The result was the selection of four items to be implemented during the detailed design phase of the Project, targeting a cost reduction of $28 million. Many of the potential value engineering items were not selected due to negative impacts on emissions, reliability and schedule.

In parallel with the Value Engineering efforts the Bechtel Project team began conducting material take-offs from the engineering drawings and documents generated in phase I and phase II. The material take-offs combined with the equipment pricing information received via procurement inquiries set the basis for the roll up of the detailed estimate. The final detailed estimate was presented to Duke Energy Indiana in March 2007.

Also during FEED Study phase III Bechtel and GE prepared a detailed execution schedule for the Project, which was finalized and provided to Duke Energy Indiana in March 2007.

The final activity of the FEED Study phase III was finalizing the Project Scope Book, which consisted of merging the design drawings and documents developed during FEED Study phases I and II into the Project Scope Book and conducting a complete page turn of the Project Scope Book with the Alliance. The Project Scope Book was completed in March, 2007.

PROJECT PERFORMANCE (OUTPUT, HEAT RATE, EMISSIONS) [CONFIDENTIAL]:

COAL PROPERTIES

The Edwardsport IGCC Plant will be designed for a defined range of coals. Indiana #5 seam coal has been identified as the performance coal. This will be used for plant performance evaluations and guarantees.

If fluxant is determined to be required for a particular fuel feed, the fluxant and coal will be blended in the coal handling system included in the Plant design. The total of any blended fuel should not exceed the below listed coal range.

Critical Coal Parameters	Units of measure	Performance Coal	Coal Range
Ultimate Analysis, dry basis			
Carbon	wt %	[redacted]	
Hydrogen	wt %	[redacted]	
Nitrogen	wt %	[redacted]	
Sulfur	wt %	[redacted]	[redacted]
Oxygen	wt %	[redacted]	
Ash	wt %	[redacted]	[redacted]
Chlorine	ppmw	[redacted]	[redacted]
Sulfur specification	Lb SO2/MMBTU		[redacted]
Reducing Ash Fluid Temp	F	[redacted]	[redacted]
Grind Top Size	inch	[redacted]	[redacted]
Hargrove Grindability Index		[redacted]	[redacted]
Equilibrium Moisture	%	[redacted]	[redacted]
As Received Moisture	%	[redacted]	[redacted]

IGCC PERFORMANCE CHARACTERISTICS

[2] The maximum percent sulfur shown is per the Reference Plant. The sulfur specification in pounds of SO2 per million BTU will, however, be the controlling specification.

The basis for the performance data for the Edwardsport IGCC Facility listed in the following table is defined as follows:

- The IGCC facility utilizing a coal with a composition in accordance with the "Performance Coal" listed in the preceding table.
- Continuous operation on syngas at an ambient temperature of 59F.
- Application of Oxygen Preheating to 250F.
- GE Steam Turbine Generator - 4F33.5
- 1% Oxygen concentration in the Nitrogen Diluent.
- Auxiliary Power loads included for Duke Energy Indiana Collector Wells and Deep Well Injection.

Parameter	Value
Combustion Turbines Gross Power Generated	[redacted]
Steam Turbine Gross Power Generated	[redacted]
Total Gross Power Generated	[redacted]
Air Separation Unit Aux. Load Consumption	[redacted]
Gasification Unit Aux. Load Consumption	[redacted]
Acid Gas Removal/Sulfur Recovery Unit/Tail Gas Unit Aux. Load Consumption	[redacted]
Balance Of Plant Aux. Load Consumption	[redacted]
Power Block Aux. Load Consumption	[redacted]
Recycle Compressor	[redacted]
Raw Water/ Collection Wells	[redacted]
Deep Wells/ Waste Water Blowdown	[redacted]
Net IGCC Facility Heat Rate (HHV)	[redacted]
Net IGCC Facility Power Output	[redacted]
Net IGCC Facility Efficiency (%)	[redacted]
Calculations	

HHV	[redacted]
Coal Feed Rate	[redacted]
02 Feed Rate (Pure)	[redacted]
	[redacted]
Energy Input	[redacted]
Net Power	[redacted]
Heat Rate (HHV)	[redacted]
Net power	[redacted]
Facility Efficiency	[redacted]

IGCC EMISSION PERFORMANCE CHARACTERISTICS

The basis for the emission performance data for the Edwardsport IGCC Facility listed in the following table is defined as follows:

- Source of Flare Pilot data is Alliance Transmittal 0002o dated July 28, 2006.
- Source of Thermal Oxidizer data is Alliance Transmittal 0002o dated July 28, 2006.
- Source of HRSG data is Alliance Transmittal 00569 dated March 30, 2007.
- HRSG emissions rates are with SCR applied.
- HRSG emissions are for one (1) HRSG. Two (2) HRSGs included in total emissions.
- PM emissions are total.
- Emissions rates are based on continuous syngas operation using performance coal parameters listed above. The Air Permit data is based on design range and operating characteristics and differs from values listed below.

	Flare Pilot	Thermal Oxidizer	HRSG	Continuous Total	
Pollutant	(lb/hr)	(lb/hr)	(lb/hr)	Pollutant, (lb/hr)	lb Pollutant/mmBTU Coal
NOx	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SO2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CO	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
VOC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONTRACTING APPROACH AND PROJECT COST ESTIMATE

Originally the GE/Bechtel Alliance preference was to develop the Project pursuant to a lump sum turn key contract ("LSTK"). Over time, however, the Alliance and Duke Energy Indiana came to the realization that a contracting approach more consistent with the approach taken by the Company on other major construction projects would be a better approach. The TSA provided for consultation between the Alliance and Duke Energy Indiana to consider a flexible contracting approach, as an alternative to the LSTK approach, which would establish acceptable targets and incentives to reflect different risk sharing options for execution of the Scope of Work for the Project, more in line with the Company's traditional approach to constructing major projects. The recent run-up in commodity pricing and competition for engineered products and labor has not only increased the estimated cost of the Project (as well as alternatives to the Project), it has made it clear that the LSTK approach is not a viable option for this Project. In order to help control the costs of the Project and avoid the extraordinary contingency amounts associated with a LTSK agreement in this environment, Duke Energy Indiana has elected to follow the approach the Company has used for construction of well over $1 billion of pollution control equipment over the last few years. Duke Energy Indiana will have more control over the construction of the Project, along with control of more of the risks. Under a LSTK contract, which would include large contingencies for commodity price increases, the Project would have been subject to such cost, whether or not the increase occurred. With the Company assuming more control and responsibility for more of the scope, the Project will incur these uncontrollable costs only if they in fact occur. It should be noted that portions of the Project may be undertaken with fixed price or lump sum contracts, as deemed appropriate by Duke Energy Indiana.

Duke Energy Indiana has worked very closely with the Alliance and the entities performing the various site studies discussed above in order to develop a more definitive cost estimate for the Project. The detailed engineering drawings produced as a part of phase II of the FEED Study discussed above provided significant amounts of details about the Project. Bechtel used this information for estimating the quantities of many of the commodities, such as piping, cable, steel and concrete, and much of the smaller equipment, such as valves and instruments, that will be necessary for the Project. Bechtel was able to perform "take-offs" from the engineering drawings, a more precise method for estimating costs. GE has provided prices for the equipment that it will manufacture (or directly procure) as well as estimates of the costs of other equipment based on pricing indications from other vendors who were supplied specifications for such equipment. The entities performing the site studies as discussed above also provided Duke Energy Indiana with details and cost estimates for various other components of the Project.

Using all of this information, Duke Energy Indiana has developed a cost estimate of $1.985 billion for the construction and completion of the Edwardsport IGCC Project. This estimate includes all purchase, supply and construction costs for the Project, including transmission costs associated with the Project, through the assumed commercial operation date in 2011. This estimate assumes that Duke Energy Indiana will manage more of the scope of the Project work, for example, Duke Energy Indiana may undertake construction of all foundations using local contractors that the Company has worked with extensively. Further, the estimate assumes that it will not be necessary to pay significant premiums to attract craft labor for the Project, assuming 40 hour work weeks with only occasional overtime. The escalation rate assumed for this estimate is 4% per year. In comparison to the Duke Energy Indiana cost estimate range presented in Mr. Moreland's prefiled testimony on October 24, 2006, this estimate, based on the extensive FEED Study analyses, represents an increase of about 5.2% over the high end of the range. This estimate is within the cost estimate range referenced in Mr. Moreland's prefiled testimony based on an Electric Power Research Institute estimate for an IGCC plant. The details supporting this estimate are available to the Commission and parties to this proceeding, subject to appropriate confidentiality protection.

CONCLUSION

Duke Energy Indiana has actively managed and particiapted in the FEED Study process. Subject to strict confidentiality agreements, Duke Energy Indiana was allowed to participate, evaluate, question and understand details of the IGCC Project with direct access to the teams developing the new product design. This active participation provided essential insight and understanding of the Project's estimated costs, schedule, performance, and future operation and risks. Going forward, Duke Energy Indiana will continue to actively participate in detailed engineering and design of the Project and will manage overall construction of the Project, in order to control Project costs consistent with its management of other major construction projects. Based on the FEED Study work and this detailed look into the GE Gasification Technology, Duke Energy Indiana has concluded that the IGCC Project is capable of meeting the Duke Energy Indiana facility objectives for a new base load coal generating station with superior environmental performance. Duke Energy Indiana believes that the Edwardsport IGCC Project provides the best option for acquiring base load generation in a timely manner to meet the needs of our customers.

EXHIBIT A

IGCC Alliance

Project Scope Book
Part I – Scope of Services
for the
Edwardsport IGCC Project

GE and Bechtel Proprietary and Confidential

Part I - Table Of Contents

Part I—Scope of Services

4.0 Procurement

4.1 General

4.2 Startup and Commissioning Spare Parts

4.3 Owner's Operating Spare Parts Inventory

Reference 4-1—Supplier/Subcontractor Quality Surveillance Plan

Reference 4-2—Suppliers/Subcontractors List for Major Equipment and Contracts

5.0 Construction

5.1 General

5.2 Construction Facilities and Services

5.3 Safety

5.4 Security

5.5 Labor Relations

5.6 Reference Points

5.7 Dangerous Material

5.8 Construction Waste Disposal

5.9 Construction Environmental Control Program

5.10 Construction Quality Control Program

Reference 5-1—Safety Plan Outline

Reference 5-2—Construction Environmental Control Plan Table of Contents

Reference 5-3—Construction Quality Control Program Outline

6.0 Scheduling, Progress Reporting, and Change Orders

6.1 General

6.2 Scheduling and Schedule Control

6.3 Progress Reports

6.4 Change Orders

IGCC Alliance

Project Scope Book
Part II – Technical Scope Description
for the
Edwardsport IGCC Project

IGCC Alliance

GE and Bechtel Proprietary and Confidential

Part II—Table Of Contents

IGCC Alliance

Part III – Table Of Contents

Part III—Appendices

Exhibit B-1

EDWARDSPORT - IGCC PROJECT

LEVEL 1- OVERALL MILESTONE SUMMARY SCHEDULE

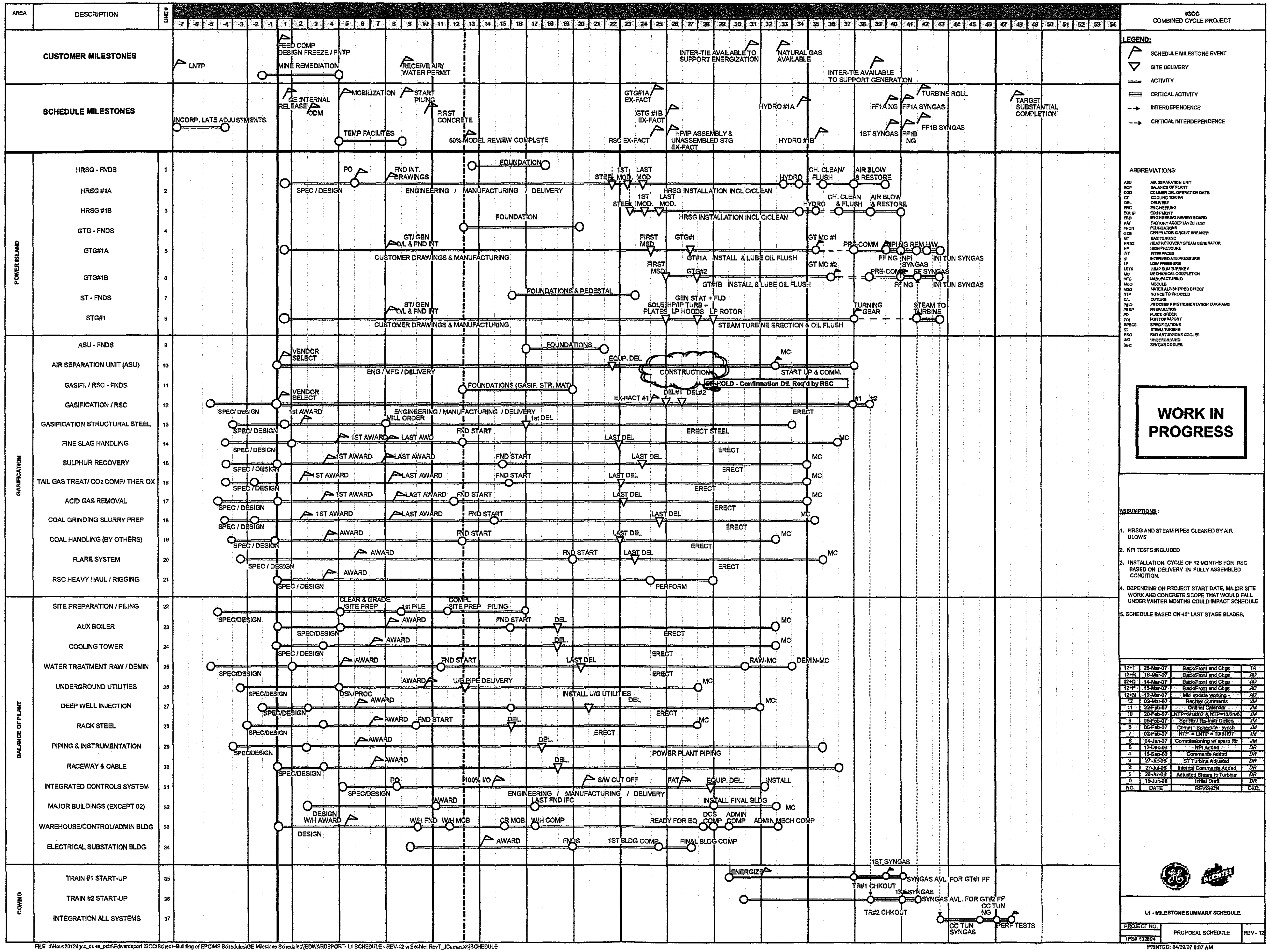
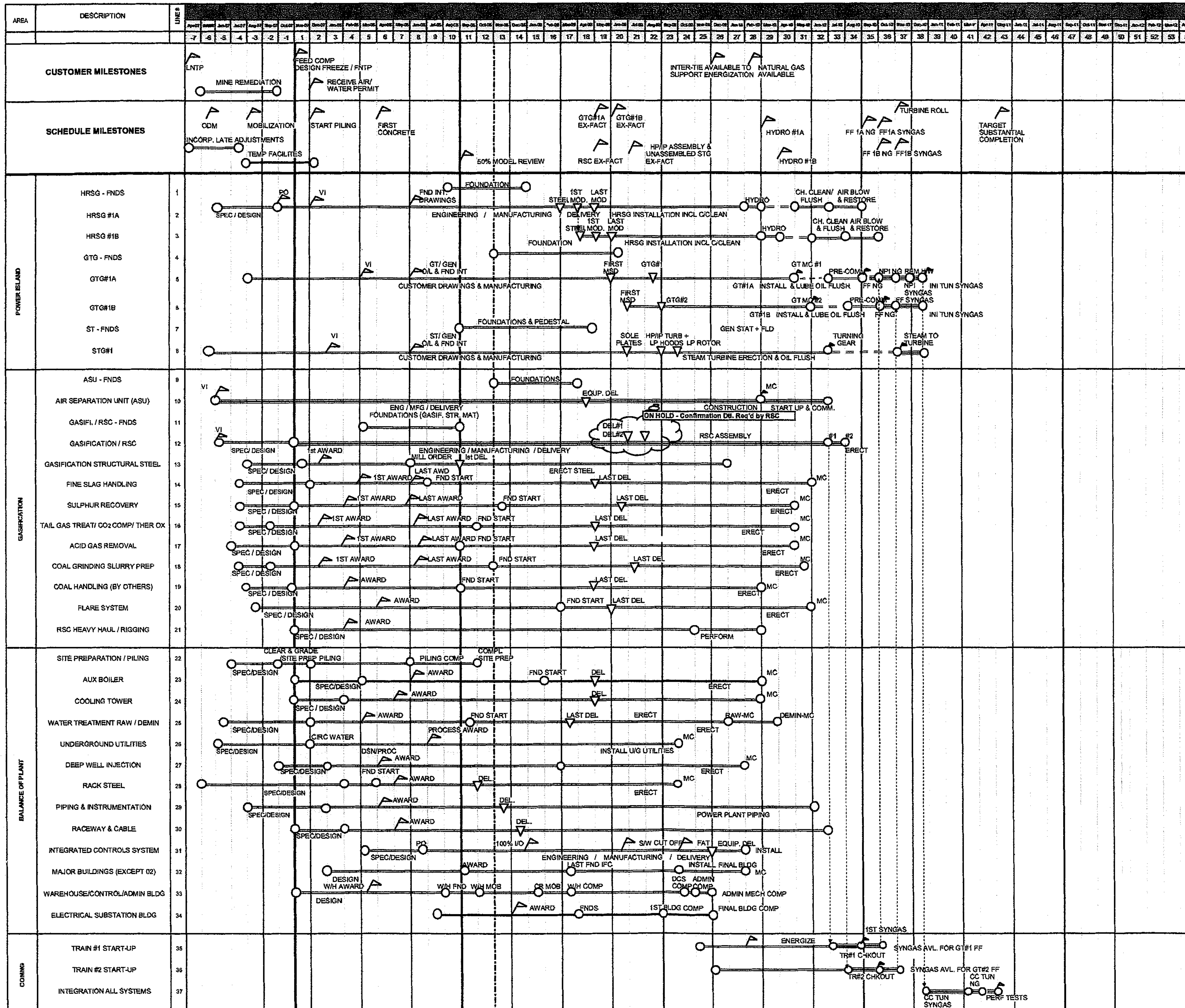


Exhibit B-2

EDWARDSPORT - IGCC PROJECT

LEVEL 1 - OVERALL MILESTONE SUMMARY SCHEDULE FOR 5/2011 TARGET COMPLETION



IGCC
COMBINED CYCLE PROJECT

LEGEND:

- SCHEDULE MILESTONE EVENT
- SITE DELIVERY
- ACTIVITY
- CRITICAL ACTIVITY
- INTERDEPENDENCE
- CRITICAL INTERDEPENDENCE

ABBREVIATIONS:

WORK IN PROGRESS

ASSUMPTIONS:

1. HRSG AND STEAM PIPES CLEANED BY AIR BLOWS
2. NPI TESTS INCLUDED
3. INSTALLATION CYCLE OF 12 MONTHS FOR RSC BASED ON DELIVERY IN FULLY ASSEMBLED CONDITION.
4. DEPENDING ON PROJECT START DATE, MAJOR SITE WORK AND CONCRETE SCOPE THAT WOULD FALL UNDER WINTER MONTHS COULD IMPACT SCHEDULE
5. SCHEDULE BASED ON 46" LAST STAGE BLADES.
6. ENGINEERING & PROC LOGICTO SUPPORT NOT CONFIRMED.
7. INCREASES CASH FLOW. MOVES EARLIER.
8. CONFIRM VI & DELIVERY DATES.
9. RSC DELIVERIES AT MONTHS 20 & 21 FROM NTP TO BE NEGOTIATED WITH THE VENDOR.

NO.	DATE	REVISION	CKD.
12+S	22-Mar-07	01May11 TGT Complt	UD
12+R	16-Mar-07	Back/Front and Chgs	AD
12+Q	14-Mar-07	Back/Front and Chgs	AD
12+P	13-Mar-07	Back/Front and Chgs	AD
12+N	12-Mar-07	Mid update working -	AD
12	02-Mar-07	Bechtel comments	JM
11	22-Feb-07	Ordinal Calendar	JM
10	20-Feb-07	LNTP=3/19/07 & NTP=10/31/07	JM
9	05-Feb-07	Spr Rtr / Re-Instr Option	JM
8	05-Feb-07	Comm Schedule synch	JM
7	02-Feb-07	NTP = LNTP = 10/31/07	JM
6	04-Jan-07	Commissioning w/ spare Rtr	JM
5	12-Dec-06	NPI Added	DR
4	15-Sep-06	Comments Added	DR
3	27-Jul-06	ST Turbine Adjusted	DR
2	27-Jul-06	Interna Comments Added	DR
1	26-Jul-06	Adjusted Steam to Turbine	DR
0	15-Jun-06	Initial Draft	DR

L1 - MILESTONE SUMMARY SCHEDULE

PROJECT NO.	PROPOSAL SCHEDULE	REV - 12
IPS# 102894		

PRINTED: 04/02/07 8:05 AM

FILE: \\Hous2012\igcc_duke_pd\Edwardsport IGCC\Sched\-Building of EPC MS Schedules\GE Milestone Schedules\[EDWARDSPORT- L1 SCHEDULE - REV-12 w Bechtel Rev S_GaryA2.xls]SCHEDULE

AUSLEY & MCMULLEN
ATTORNEYS AND COUNSELORS AT LAW
227 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

ORIGINAL

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07 APR -2 PM 3:01
COMMISSION CLERK

April 2, 2007

HAND DELIVERED

Ms. Blanca S. Bayo, Director
Division of Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

070000

Re: Tampa Electric Company's Ten-Year Site Plan

Dear Ms. Bayo:

Enclosed for filing on behalf of Tampa Electric Company are twenty-five (25) copies of the company's January 2007 to December 2016 Ten-Year Site Plan.

Also enclosed is a CD containing the above Ten-Year Site Plan in PDF format.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

CMP
COM
CTR
ECR 21
GCL
OPC
RCA
SCR
SGA
SEC
OTH 2 - K. Pena

RECEIVED & FILED

FPSC-BUREAU OF RECORDS

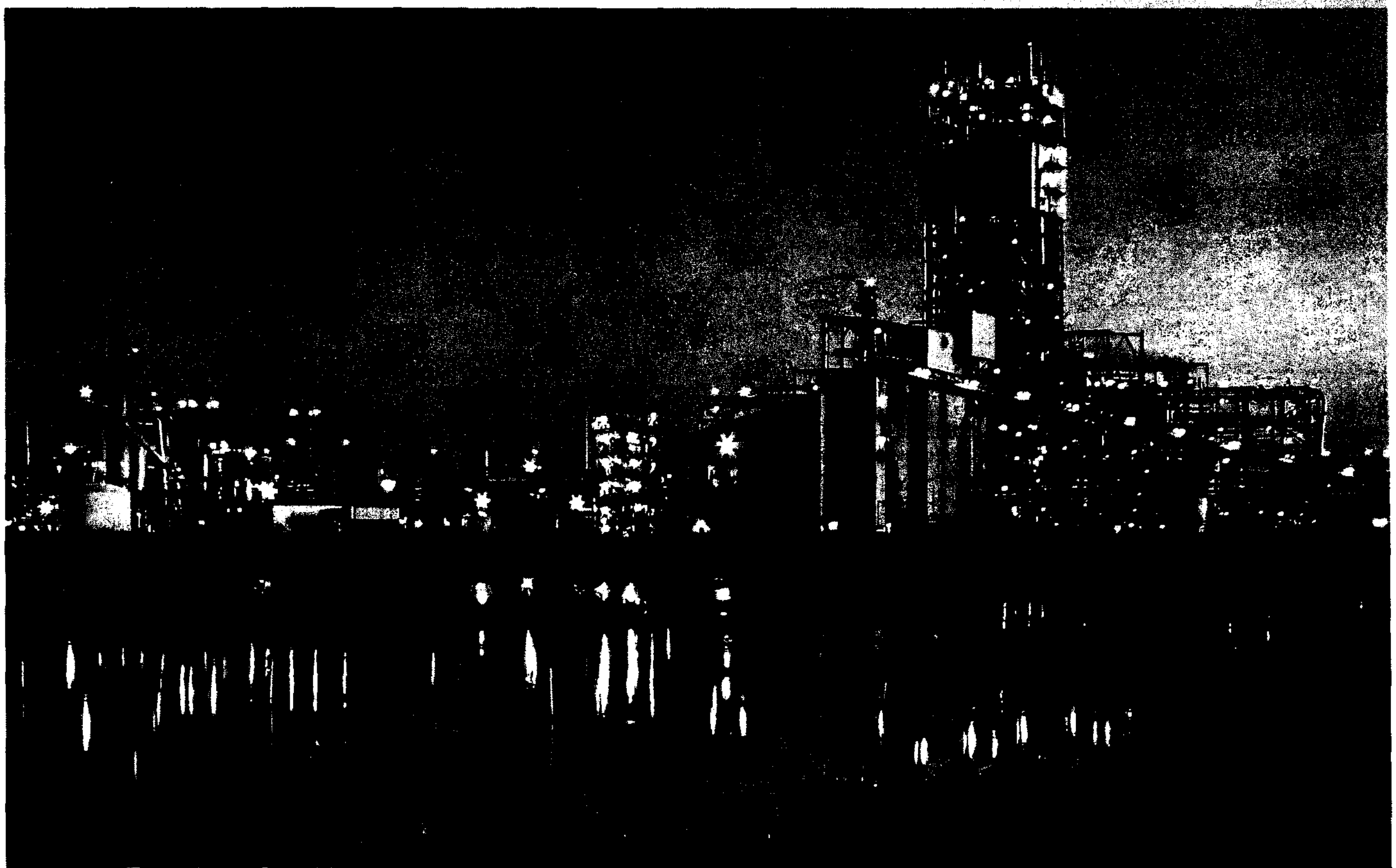
DOCUMENT NUMBER-DATE
02864 APR-2 07
FPSC-COMMISSION CLERK

TECO
TAMPA ELECTRIC

Ten -Year Site Plan for Electrical Generating Facilities and Associated Transmission Lines

January 2007 to December 2016

TAMPA ELECTRIC
Polk Power Station's Integrated Gasification
Combined-Cycle (IGCC) Facility



Responsibly Serving Our Growing Customers' Needs.

TEN-YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES

January 2007 to December 2016

TAMPA ELECTRIC COMPANY
Tampa, Florida

April 1, 2007

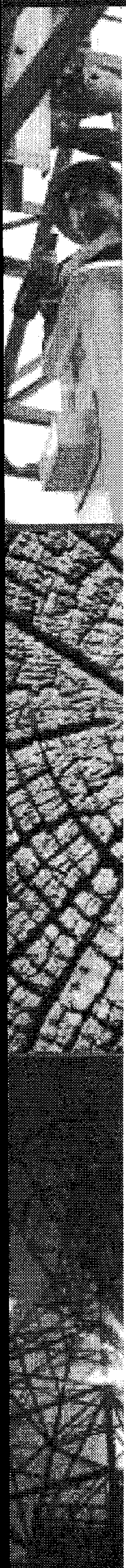


Table of Contents

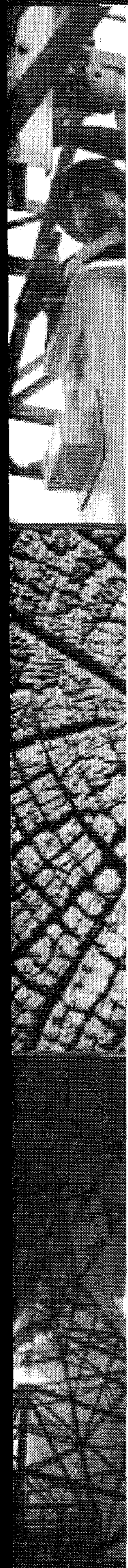


Table of Contents

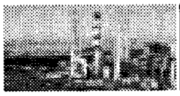
list of schedules

glossary of terms

CODE IDENTIFICATION SHEET

Unit Type:	CT	=	Combustion Turbine
	CC	=	Combined Cycle
	CG	=	Coal Gasifier
	D	=	Diesel
	FS	=	Fossil Steam
	HRSG	=	Heat Recovery Steam Generator
	IGCC	=	Integrated Gasification Combined Cycle
	ST	=	Steam Turbine
Unit Status:	P	=	Planned
	T	=	Regulatory Approval Received
	LTRS	=	Long Term Reserve Stand-by
	UC	=	Under Construction
Fuel Type:	BIT	=	Bituminous Coal
	C	=	Coal
	PC	=	Petroleum Coke
	RFO	=	Residual Fuel Oil (#6 Oil)
	DFO	=	Distillate Fuel Oil (#2 Oil)
	NG	=	Natural Gas
	WH	=	Waste Heat
Environmental:	CL	=	Closed Loop Water Cooled
	CLT	=	Cooling Tower
	EP	=	Electrostatic Precipitator
	FQ	=	Fuel Quality
	LS	=	Low Sulfur
	FGD	=	Flue Gas Desulfurization
	OLS	=	Open Loop Cooling Water System
	OTS	=	Once-Through System
	NR	=	Not Required
Transportation:	PL	=	Pipeline
	TK	=	Truck
	RR	=	Railroad
	WA	=	Water
Other:	N	=	None

chapter 1



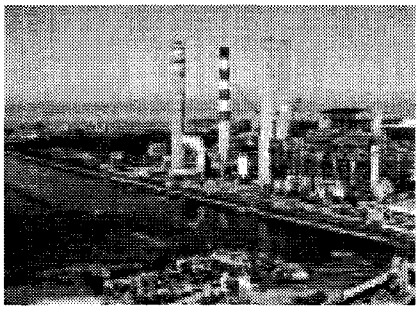
Description of Existing Facilities

Tampa Electric has five (5) generating stations that include fossil steam units, combined cycle units, combustion turbine peaking units, an integrated coal gasification combined cycle unit, and internal combustion diesel units.

Description of Electric Generating Facilities

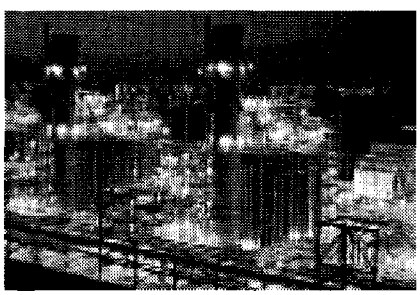
Big Bend

The station contains four (4) pulverized coal fired steam units equipped with desulfurization scrubbers, electrostatic precipitators and three (3) distillate fueled combustion turbines. These coal units are currently undergoing the addition of air pollution control systems called Selective Catalytic Reduction (SCR), this work is scheduled to be completed by 2010.



H.L. Culbreath Bayside

The station contains two (2) natural gas fired combined cycle units. Bayside Unit 1 utilizes three (3) combustion turbines, three (3) heat recovery steam generators (HRSGs) and one (1) steam turbine. Bayside Unit 2 utilizes four (4) combustion turbines, four (4) HRSGs and one (1) steam turbine.



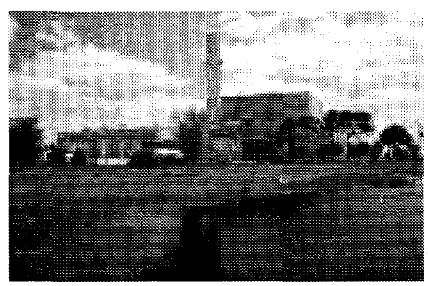
Polk Power Station

The station is presently comprised of four (4) generating units and one (1) unit under construction. Polk Unit 1 is fired with synthetic gas produced from gasified coal and other carbonaceous fuels and is an integrated gasification combined cycle unit (IGCC). This technology integrates state-of-the-art environmental processes to create a clean fuel gas from a variety of feedstock with the efficiency benefits of combined cycle generation equipment. Polk Units 2 through 5 are combustion turbines. Units 2 and 3 are fueled primarily with natural gas with distillate backup. Unit 4 was placed in-service March 2007 and is fueled with natural gas. Unit 5 scheduled for in-service May 2007 is fueled with natural gas. Polk Units 4 and 5 each have a capacity rating of 180 MW winter and 160 MW summer.

Other Facilities

Phillips

The station is comprised of two (2) residual or distillate oil fired diesel engines.



Partnership

The station is comprised of two (2) natural gas fired diesel engines.

Schedule 1

Existing Generating Facilities
As of December 31, 2006

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt	Commercial	Expected	Gen. Max.	Net Capability	
	Unit		Unit	Fuel		Fuel Transport		Fuel	In-Service	Retirement	Nameplate	Summer	Winter
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Days	Mo/Yr	Mo/Yr	KW	MW	MW
Big Bend		Hillsborough											
		Co. 14/31S/19E									**1,998,000**	**1,760**	**1,815**
	1		ST	BIT	N	WA	N	0	10/70	Unknown	445,500	391	401
	2		ST	BIT	N	WA	N	0	04/73	"	445,500	391	401
	3		ST	BIT	N	WA	N	0	05/76	"	445,500	414 (b)	423 (b)
	4		ST	BIT	N	WA	N	0	02/85	"	486,000	447	452
	CT 1		GT	DFO	N	WA	TK	0	02/69	01/15	18,000	12	13
	CT 2		GT	DFO	N	WA	TK	0	11/74	01/15	78,750	60	80
	CT 3		GT	DFO	N	WA	TK	0	11/74	01/15	78,750	45	45
Bayside		Hillsborough											
		Co. 4/30S/19E									**2,014,160**	**1,632**	**1,841**
	1		CC	NG	N	PL	N	0	4/03	Unknown	809,060	702	793
	2		CC	NG	N	PL	N	0	1/04	Unknown	1,205,100	930	1,048
Phillips		Highland Co.											
		12-055									**38,430**	**34**	**36**
	1		IC	RFO	N	TK	N	0	06/83	Unknown	19,215	17	18
	2		IC	RFO	N	TK	N	0	06/83	Unknown	19,215	17	18
Polk		Polk Co.											
		2,3/32S/23E									**677,839**	**580**	**628**
	1		IGCC	BIT	DFO	WA/TK	TK	0	09/96	Unknown	326,299	255	260
	2 (a)		GT	NG	DFO	PL	TK	0	07/00	Unknown	175,770	160	184
	3 (a)		GT	NG	DFO	PL	TK	0	5/02	Unknown	175,770	165	184
Partnership		Hillsborough											
		Co. W30/29/19									**5,800**	**6**	**6**
	1		IC	NG	N	PL	N	0	04/01	Unknown	2,900	3	3
	2		IC	NG	N	PL	N	0	04/01	Unknown	2,900	3	3
											TOTAL	**4,012**	**4,326**

Notes: (a) Polk Units 2 & 3 turbine name plate rating are based on 59 deg. F. The net capacity of these units vary with ambient air temperature.

(b) Big Bend Unit 3 derated (summer 50 MW/ winter 50 MW) until December 2007 outage.

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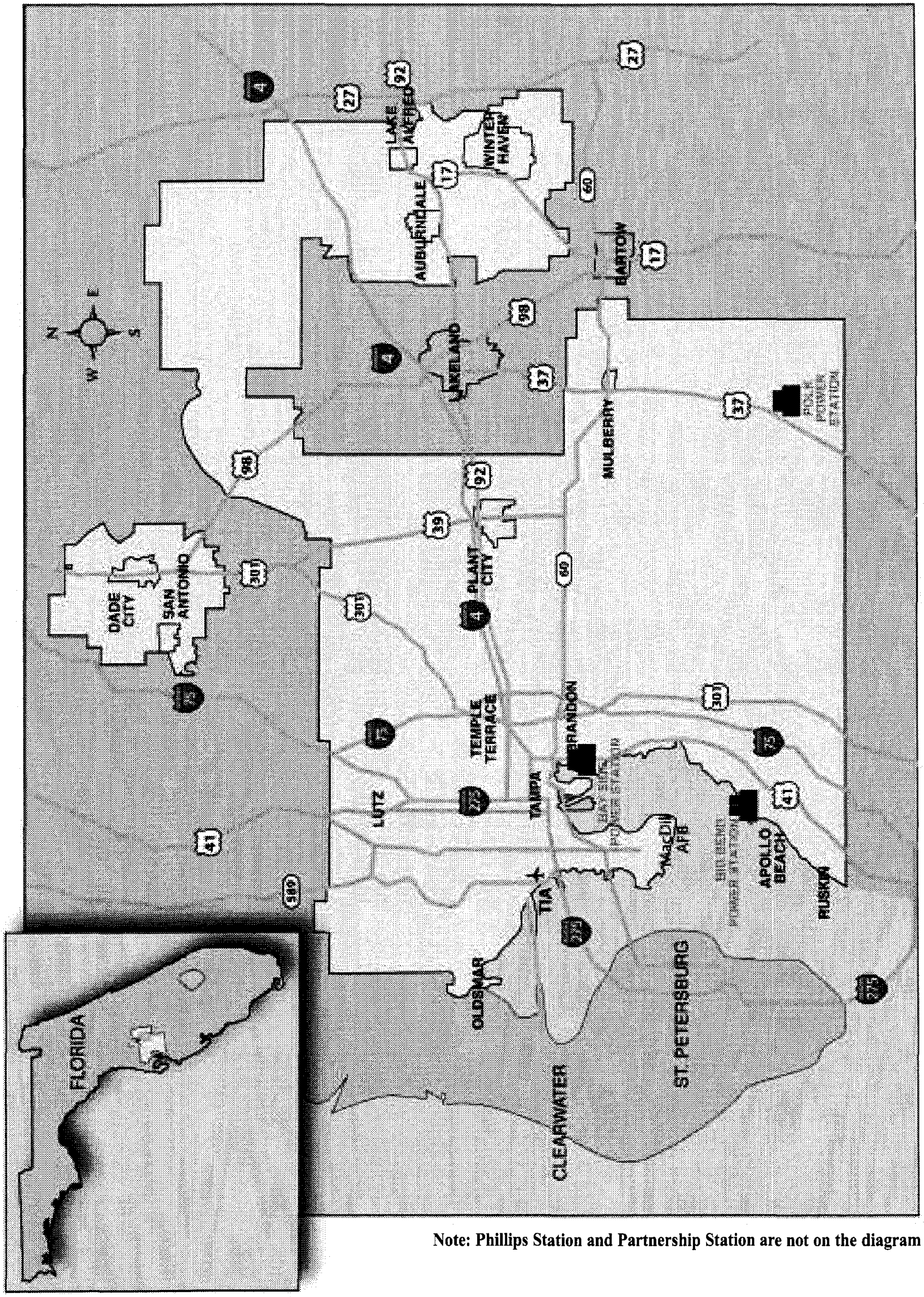
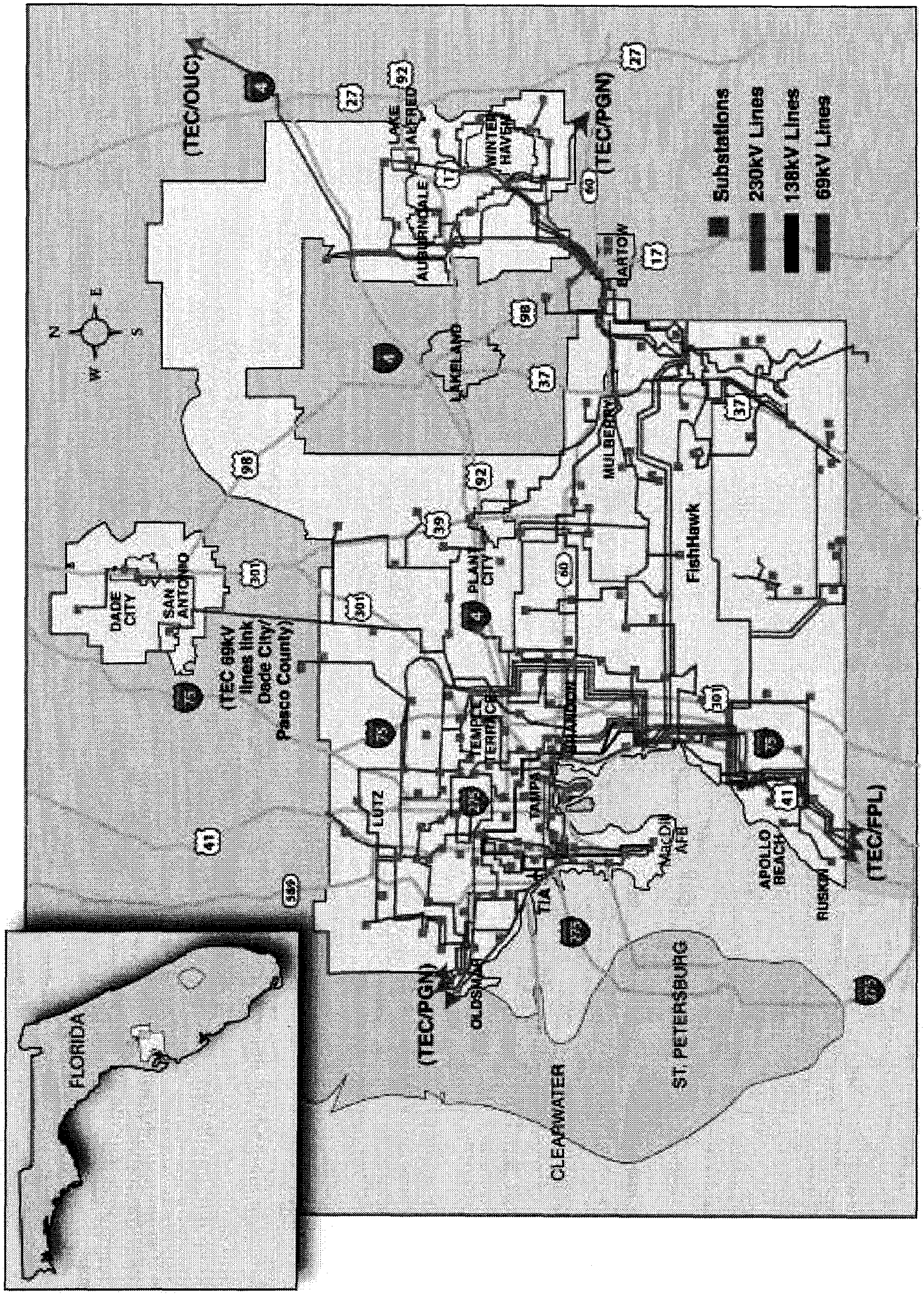
Tampa Electric Service Area & Generating Plant Map



Note: Phillips Station and Partnership Station are not on the diagram

Tampa Electric Service Area Transmission Facility



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chapter 2

Forecast of Electric Power, Demand and Energy Consumption

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average kWh Consumption Per Customer	GWH	Customers*	Average kWh Consumption Per Customer
1997	928,731	2.4	6,500	456,175	14,249	4,902	56,981	86,029
1998	942,322	2.4	7,050	466,189	15,123	5,173	58,542	88,364
1999	962,153	2.4	6,967	477,533	14,590	5,337	60,089	88,818
2000	1,006,400	2.6	7,369	491,925	14,980	5,541	61,902	89,512
2001	1,030,900	2.6	7,594	505,964	15,009	5,685	63,316	89,788
2002	1,053,900	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,084,198	2.5	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,106,487	2.5	8,293	544,313	15,236	5,988	67,488	88,727
2005	1,127,449	2.5	8,558	558,601	15,320	6,233	69,027	90,298
2006	1,161,959	2.5	8,721	575,111	15,164	6,357	70,205	90,549
2007	1,187,727	2.5	9,277	589,307	15,742	6,619	71,900	92,061
2008	1,214,066	2.5	9,570	603,394	15,861	6,800	73,327	92,737
2009	1,240,988	2.5	9,881	617,561	15,999	6,993	74,753	93,553
2010	1,267,305	2.5	10,192	631,430	16,142	7,189	76,153	94,408
2011	1,290,727	2.5	10,505	645,029	16,286	7,389	77,530	95,310
2012	1,314,377	2.5	10,829	659,079	16,431	7,592	78,927	96,186
2013	1,339,471	2.5	11,174	673,981	16,579	7,812	80,367	97,202
2014	1,362,985	2.5	11,525	689,615	16,713	8,040	81,842	98,238
2015	1,386,990	2.4	11,871	705,667	16,822	8,270	83,335	99,242
2016	1,408,645	2.4	12,240	721,830	16,957	8,504	84,830	100,253

December 31, 2006 Status

* Average of end-of-month customers for the calendar year.

Schedule 2.2

History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial				Street &	Other Sales	Total Sales
			Average kWh	Railroads	Highway	to Public	to Ultimate
			Consumption	and Railways	Lighting	Authorities	Consumers
Year	GWH	Customers*	Per Customer	GWH	GWH	GWH	GWH
1997	2,465	629	3,918,919	0	53	1,170	15,090
1998	2,520	682	3,695,015	0	54	1,231	16,028
1999	2,223	740	3,004,054	0	52	1,226	15,805
2000	2,390	776	3,079,897	0	53	1,285	16,638
2001	2,329	851	2,736,780	0	54	1,314	16,976
2002	2,612	948	2,755,274	0	55	1,380	17,925
2003	2,580	1203	2,144,638	0	57	1,481	18,226
2004	2,556	1,299	1,967,667	0	58	1,542	18,437
2005	2,478	1,337	1,853,403	0	60	1,582	18,911
2006	2,279	1,485	1,534,680	0	61	1,607	19,025
2007	2,323	1,441	1,612,337	0	63	1,690	19,972
2008	2,359	1,479	1,594,340	0	65	1,741	20,536
2009	2,394	1,532	1,562,794	0	67	1,795	21,130
2010	2,429	1,589	1,528,608	0	69	1,843	21,722
2011	2,461	1,647	1,494,129	0	70	1,888	22,313
2012	2,494	1,706	1,461,599	0	72	1,934	22,921
2013	2,525	1,768	1,428,175	0	74	1,983	23,568
2014	2,557	1,835	1,393,264	0	75	2,037	24,234
2015	2,589	1,907	1,357,578	0	77	2,093	24,900
2016	2,623	1,983	1,322,443	0	78	2,148	25,593

December 31, 2006 Status

* Average of end-of-month customers for the calendar year.

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
1997	507	731	16,328	4,583	518,368
1998	431	783	17,242	4,839	530,252
1999	533	900	17,238	5,299	543,661
2000	763	972	18,373	5,497	560,100
2001	684	794	18,454	5,649	575,780
2002	502	935	19,362	6,032	590,199
2003	587	985	19,798	6,399	604,900
2004	589	945	19,971	6,435	619,535
2005	712	952	20,575	6,656	635,621
2006	700	1,000	20,725	6,905	653,706
2007	682	1,019	21,672	7,002	669,650
2008	665	1,047	22,248	7,166	685,366
2009	634	1,076	22,840	7,332	701,178
2010	616	1,107	23,445	7,494	716,666
2011	285	1,137	23,735	7,653	731,859
2012	222	1,167	24,310	7,816	747,528
2013	137	1,200	24,905	7,989	764,104
2014	78	1,234	25,547	8,169	781,462
2015	78	1,267	26,246	8,354	799,264
2016	79	1,302	26,974	8,540	817,184

December 31, 2006 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
** Utility Use and Losses include accrued sales.
*** Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
**** Average of end-of-month customers for the calendar year.

Schedule 3.1

History and Forecast of Summer Peak Demand
Base Case

(1) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1997	3,187	106	3,081	225	95	39	21	24	2,677
1998	3,458	111	3,347	204	107	43	21	27	2,945
1999	3,648	190	3,458	193	98	48	19	31	3,069
2000	3,568	171	3,397	182	78	52	21	36	3,028
2001	3,730	178	3,552	181	90	55	21	40	3,165
2002	3,869	122	3,747	206	99	60	21	43	3,318 ☑
2003	3,854	122	3,732	188	63	65	21	44	3,351
2004	3,974	120	3,854	177	95	70	20	47	3,445
2005	4,218	128	4,090	144	79	73	19	49	3,725
2006	4,265	128	4,137	146	77	77	18	50	3,769
2007	4,421	187	4,234	150	66	78	16	52	3,872
2008	4,542	187	4,355	150	63	80	17	53	3,991
2009	4,656	177	4,479	150	62	82	17	55	4,113
2010	4,780	177	4,603	150	61	84	18	56	4,235
2011	4,833	105	4,727	150	60	86	18	56	4,357
2012	4,962	105	4,856	150	59	87	19	57	4,484
2013	5,084	90	4,995	150	58	89	20	58	4,620
2014	5,217	77	5,141	150	58	90	20	58	4,765
2015	5,368	77	5,292	150	57	91	20	59	4,915
2016	5,522	77	5,445	150	56	92	20	59	5,068

December 31, 2006 Status

* Includes residential and commercial/industrial conservation.

** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.

☑ Net Firm Demand is not coincident with system peak.

Note: Values shown may be affected due to rounding.

Schedule 3.2

History and Forecast of Winter Peak Demand
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total *	Wholesale **	Retail *	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
1996/97	3,632	109	3,523	228	164	353	21	38	2,719
1997/98	3,231	99	3,132	210	160	370	21	39	2,332
1998/99	3,985	131	3,854	152	266	388	18	40	2,990
1999/00	4,019	125	3,894	212	209	402	19	43	3,009
2000/01	4,405	136	4,269	191	196	410	21	44	3,407
2001/02	4,217	127	4,090	168	176	419	22	46	3,259
2002/03	4,484	129	4,355	195	210	428	21	46	3,455
2003/04	3,949	120	3,829	254	136	437	18	48	2,936
2004/05	4,308	129	4,179	194	189	444	16	49	3,287
2005/06	4,404	171	4,233	51	144	447	18	50	3,523
2006/07	5,057	191	4,866	160	143	452	16	50	4,046
2007/08	5,185	191	4,994	160	134	455	16	51	4,178
2008/09	5,303	178	5,124	160	131	458	17	51	4,308
2009/10	5,436	178	5,257	160	128	461	17	52	4,440
2010/11	5,565	178	5,387	160	126	463	18	52	4,568
2011/12	5,627	107	5,520	160	124	465	18	52	4,700
2012/13	5,752	91	5,660	160	123	467	19	52	4,839
2013/14	5,887	77	5,810	160	121	469	19	53	4,988
2014/15	6,043	77	5,967	161	120	470	20	53	5,143
2015/16	6,203	77	6,126	160	118	471	20	53	5,304

December 31, 2006 Status

* Includes cumulative conservation.
** Includes sales to Progress Energy Florida, Wauchula, Fort Meade, St. Cloud and Reedy Creek.
Note: Values shown may be affected due to rounding.

Schedule 3.3

History and Forecast of Annual Net Energy for Load - GWH
Base Case

(1) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale *	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load ** Factor %
1997	15,430	279	61	15,090	507	731	16,328	57.5
1998	16,400	297	76	16,027	431	783	17,241	58.1
1999	16,212	315	92	15,805	533	900	17,238	55.1
2000	17,083	333	112	16,638	763	972	18,373	58.5
2001	17,444	346	122	16,976	684	794	18,454	53.3
2002	18,423	361	137	17,925	502	935	19,362	58.7
2003	18,756	378	152	18,226	587	985	19,799	56.4
2004	18,999	394	168	18,437	589	945	19,971	58.9
2005	19,491	404	176	18,911	712	952	20,575	57.3
2006	19,625	412	188	19,025	700	1000	20,725	57.2
2007	20,579	418	189	19,972	682	1019	21,672	54.3
2008	21,155	425	195	20,536	665	1047	22,248	54.1
2009	21,760	431	200	21,130	634	1076	22,840	54.4
2010	22,362	436	204	21,722	616	1107	23,445	54.4
2011	22,963	441	208	22,313	285	1137	23,735	53.7
2012	23,578	446	211	22,921	222	1167	24,310	54.2
2013	24,232	450	214	23,568	137	1200	24,905	54.3
2014	24,904	453	216	24,234	78	1234	25,547	54.4
2015	25,574	456	217	24,900	78	1267	26,246	54.3
2016	26,269	459	217	25,593	79	1302	26,974	54.1

December 31, 2006 Status

* Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
** Load Factor is the ratio of total system average load to peak demand.

Schedule 4

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2006 Actual		2007 Forecast		2008 Forecast	
	Peak Demand *	NEL **	Peak Demand *	NEL **	Peak Demand *	NEL **
Month	MW	GWH	MW	GWH	MW	GWH
January	3,204	1,546	4,555	1,629	4,679	1,691
February	3,906	1,410	3,746	1,443	3,852	1,483
March	2,952	1,518	3,528	1,600	3,626	1,630
April	3,587	1,639	3,496	1,584	3,591	1,621
May	3,753	1,831	3,982	1,922	4,088	1,971
June	3,951	1,967	4,174	2,022	4,285	2,070
July	4,046	2,040	4,300	2,178	4,416	2,227
August	4,138	2,135	4,291	2,205	4,408	2,246
September	3,840	1,915	4,141	2,036	4,254	2,082
October	3,665	1,732	3,866	1,869	3,974	1,920
November	3,128	1,468	3,504	1,550	3,605	1,600
December	2,799	1,526	3,748	1,634	3,855	1,707
TOTAL		20,725		21,673		22,248

December 31, 2006 Status

* Peak demand represents total retail and wholesale demand, excluding conservation impacts.
** Values shown may be affected due to rounding.

Schedule 5

History and Forecast of Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Actual	Actual										
	Fuel Requirements		Unit	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	4,072	4,637	4,344	4,241	4,220	4,175	4,358	4,349	4,754	4,630	4,652	4,718
(3)	Residual	Total	1000 BBL	110	47	28	9	2	1	5	5	1	2	3	3
(4)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel (A)	1000 BBL	110	47	28	9	2	1	5	5	1	2	3	3
(8)	Distillate	Total	1000 BBL	116	78	90	96	91	88	97	92	94	94	88	96
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	75	71	87	91	89	86	91	85	91	91	86	91
(11)		CT	1000 BBL	42	7	3	6	2	2	6	7	3	3	3	4
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	54,391	51,740	58,109	60,105	60,802	60,980	62,032	64,522	49,804	54,118	58,466	65,421
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	53,166	49,823	57,179	58,255	60,089	59,636	58,662	60,383	47,988	51,354	54,247	58,660
(16)		CT	1000 MCF	1,225	1,917	931	1,850	714	1,344	3,370	4,139	1,817	2,764	4,219	6,761
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	362	383	519	637	625	617	651	623	2010	2005	2037	1882

* Values shown may be affected due to rounding.
** All values exclude ignition.
(A) Phillips Unit 3 retired March 2006, data reported as diesel for Phillips Units 1 and 2.

Schedule 6.1

History and Forecast of Net Energy for Load by Fuel Source in GWH

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Unit	Actual 2005	Actual 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	Annual Firm Interchange		GWH	209	369	785	347	206	269	588	712	288	324	313	303
(2)	Nuclear		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWH	8,705	9,906	9,398	9,285	9,144	9,021	9,447	9,367	10,249	9,963	10,017	10,162
(4)	Residual	Total	GWH	71	29	18	6	1	1	3	3	1	1	2	2
(5)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel (A)	GWH	71	29	18	6	1	1	3	3	1	1	2	2
(9)	Distillate	Total	GWH	64	45	49	52	49	48	53	49	51	51	48	52
(10)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	47	42	48	50	49	47	50	47	50	50	47	50
(12)		CT	GWH	18	2	1	2	1	1	3	3	1	2	1	2
(13)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH	7,567	7,136	8,020	8,254	8,416	8,414	8,451	8,775	6,814	7,373	7,934	8,811
(15)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWH	7,461	6,971	7,942	8,098	8,357	8,294	8,157	8,411	6,662	7,130	7,530	8,153
(17)		CT	GWH	106	165	78	156	59	120	294	364	152	243	404	658
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWH	955	1,011	1,368	1,681	1,651	1,631	1,720	1,644	5,807	5,794	5,899	5,422
(20)	Net Interchange		GWH	2,470	1,654	1,508	2,097	2,845	3,695	3,157	3,538	1,475	1,820	1,812	2,012
(21)	Purchased Energy from														
(22)	Non-Utility Generators		GWH	534	576	526	527	526	366	317	222	221	221	221	208
(23)	Net Energy for Load*		GWH	20,575	20,725	21,671	22,248	22,839	23,444	23,736	24,309	24,906	25,547	26,246	26,972

* Values shown may be affected due to rounding.

(A) Phillips Unit 3 retired March 2006, data reported as diesel for Phillips Units 1 and 2.

Schedule 6.2

History and Forecast of Net Energy for Load by Fuel Source as Percentage

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Actual	Actual										
	Energy Sources		Unit	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	*Annual Firm Interchange*		%	1.0	1.8	3.6	1.6	0.9	1.1	2.5	2.9	1.2	1.3	1.2	1.1
(2)	Nuclear		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(3)	Coal		%	42.3	47.8	43.4	41.7	40.0	38.5	39.8	38.5	41.1	39.0	38.2	37.7
(4)	Residual	Total	%	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)		Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)		CC (A)	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)		Diesel	%	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Distillate	Total	%	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(10)		Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CC	%	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(12)		CT	%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Natural Gas	Total	%	36.8	34.4	37.0	37.1	36.8	35.9	35.6	36.1	27.4	28.9	30.2	32.7
(15)		Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(16)		CC	%	36.3	33.6	36.6	36.4	36.6	35.4	34.4	34.6	26.7	27.9	28.7	30.2
(17)		CT	%	0.5	0.8	0.4	0.7	0.3	0.5	1.2	1.5	0.6	1.0	1.5	2.4
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		%	4.6	4.9	6.3	7.6	7.2	7.0	7.2	6.8	23.3	22.7	22.5	20.1
(20)	Net Interchange		%	12.0	8.0	7.0	9.4	12.5	15.8	13.3	14.6	5.9	7.1	6.9	7.5
(21)	Purchased Energy from														
(22)	Non-Utility Generators		%	2.6	2.8	2.4	2.4	2.3	1.6	1.3	0.9	0.9	0.9	0.8	0.8
(23)	Net Energy for Load*		%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

* Values shown may be affected due to rounding.
(A) Phillips Unit 3 retired March 2006, data reported as diesel for Phillips Units 1 and 2.

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chapter 3

Tampa Electric Company Forecasting Methodology

The Customer, Demand and Energy Forecast is the foundation from which the integrated resource plan is developed. Recognizing its importance, Tampa Electric employs the necessary methodologies for carrying out this function. The primary objective of this procedure is to blend proven statistical techniques with practical forecasting experience to provide a projection, which represents the highest probability of occurrence.

This chapter is devoted to describing Tampa Electric's forecasting methods and the major assumptions utilized in developing the 2007-2016 forecasts. The data tables in Chapter II outline the expected customer, demand, and energy values for the 2007-2016 time period.

Retail Load

MetrixND, an advanced statistics program for analysis and forecasting, was used to develop the 2007-2016 Customer, Demand and Energy forecasts. This software provides a platform for the development of more dynamic and fully integrated models.

In addition, Tampa Electric uses MetrixLT, which integrates with MetrixND to develop multiple-year forecasts of energy usage at the hourly level. This tool allows the annual or monthly forecasts in MetrixND to be combined with hourly load shape data to develop a long-term "bottom-up" forecast, which is consistent with short-term statistical forecasts.

Tampa Electric's retail customer, demand and energy forecasts are the result of six separate forecasting analyses:

1. economic analysis;
2. customer analysis;
3. energy analysis;
4. peak demand analysis;
5. phosphate analysis; and
6. Demand Side Management analysis

The MetrixND models are the company's most sophisticated and primary load forecasting models. The phosphate demand and energy is forecasted separately and then combined in the final forecast. Likewise, the effect of Tampa Electric's conservation, load management, and cogeneration programs is incorporated into the process by subtracting the expected reduction in demand and energy from the forecast.

1. Economic Analysis

The economic assumptions used in the forecast models are derived from forecasts from Economy.com and the University of Florida's Bureau of Economic and Business Research (BEBR).

See the "Base Case Forecast Assumptions" section of this chapter for an explanation of the most significant economic inputs to the MetrixND models.

2. Customer Multiregression Model

The customer multiregression forecasting model is an eight-equation model. The equations forecast the number of customers by eight major categories. The primary economic drivers in the customer forecast models are state population estimates, service area households and Hillsborough County employment growth.

1. ***Residential Customer Model***: Customer projections are a function of Florida's population. Since a strong correlation exists between historical changes in service area customers and historical changes in Florida's population, Florida population estimates for 2007-2026 were used to forecast the future growth patterns in residential customers.
2. ***Commercial Customer Model***: Total commercial customers include commercial customers plus temporary service customers (temporary poles on construction sites); therefore, two models are used to forecast total commercial customers:
   a. The Commercial Customer Model is a

function of residential customers. An increase in the number of households provides the need for additional services, restaurants, and retail establishments. The amount of residential activity also plays a part in the attractiveness of the Tampa Bay area as a place to relocate or start a new business.

b. Projections of employment in the construction sector are a good indicator of expected increases and decreases in local construction activity. Therefore, the Temporary Service model projects the number of customers as a function of construction employment.

3. ***Industrial Customer Model (Non-Phosphate):*** Non-phosphate industrial customers include three rate classes that have been modeled individually: General Service, General Service Demand and General Service Large Demand.

a. The General Service Customer Model is a function of Hillsborough County commercial employment.

b. The General Service Demand Customer Model is a function of Hillsborough County commercial employment. Since the structure of our local industrial sector has been shifting from an energy-intense manufacturing sector to a non-energy intense manufacturing sector, the type of customers in this sector have qualities of large scaled commercial customers.

c. The General Service Large Demand Customer Model is a function of Hillsborough County Manufacturing Employment.

4. **Public Authority Customer Model:** Customer projections are a function of Florida's population. The need for public services will depend on the number of people in the region; therefore, consistent with the residential customer model, Florida's population projections are used to determine future growth in the public authorities sector.

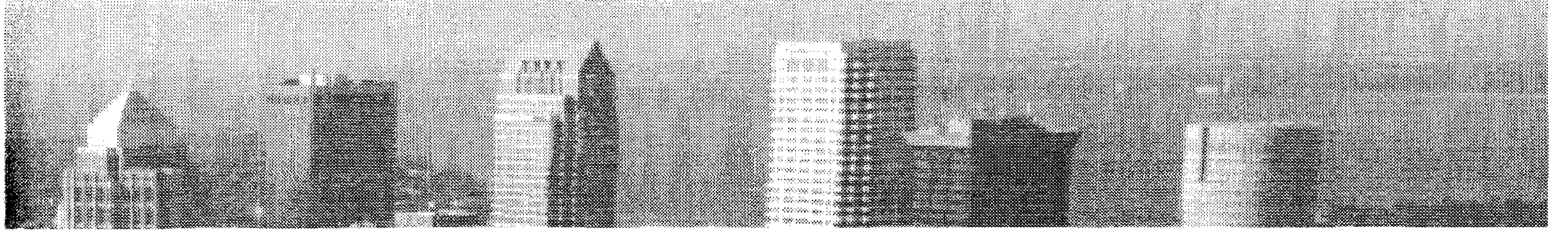
5. **Street & Highway Lighting Customer Model:** As the number of commercial customers increases so does the need for infrastructure expansion, such as street and highway lighting. Therefore, the commercial customer forecast is the basis for the Street & Highway Lighting customer model.

3. Energy Multiregression Model

There are a total of eight energy models. All of these models represent average usage per customer (kWh/customer), except for the temporary services model which represents total kWh sales. The average usage models interact with the customer models to arrive at total sales for each class.

The energy models are based on an approach known as Statistically Adjusted Engineering (SAE). SAE entails specifying end-use variables, such as heating, cooling and base use appliance/equipment, and incorporating these variables into regression models. This approach allows the models to capture long-term structural changes that end-use models are known for, while also performing well in the short-term time frame, as do econometric regression models.

1. ***Residential Energy Model***: The residential forecast model is made up of three major components: (1) The end-use equipment index variables, which capture the long-term net effect of equipment saturation and equipment efficiency improvements; (2) The second component serves to capture changes in the economy such as



household income, household size, and the price of electricity; and, (3) The third component is made up of weather variables, which serve to allocate the seasonal impacts of weather throughout the year. The SAE model framework begins by defining energy use for an average customer in year (y) and month (m) as the sum of energy used by heating equipment (XHeat y,m), cooling equipment (XCool y,m), and other equipment (XOther y,m). The XHeat, XCool, and XOther variables are defined as a product of an **annual equipment index** and a **monthly usage multiplier**.

$$\textbf{Average Usage}_{y,m} = (\textbf{XHeat}_{y,m} + \textbf{XCool}_{y,m} + \textbf{XOther}_{y,m})$$

Where:

$$\textbf{XHeat}_{y,m} = \text{HeatEquipIndex y} \times \text{HeatUse y,m}$$

$$\textbf{XCool}_{y,m} = \text{CoolEquipIndex y} \times \text{CoolUse y,m}$$

$$\textbf{XOtherUse}_{y,m} = \text{OtherEquipIndex y} \times \text{OtherUse y,m}$$

The **annual equipment variables** (*HeatEquipIndex, CoolEquipIndex, OtherEquipIndex*) are defined as a weighted average across equipment types multiplied by equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations and operating efficiencies. The weights are defined by the estimated energy use per household for each equipment type in the base year.

Where:

$$\text{HeatEquipIndex} = \sum_{\text{Tech}} \text{Weight} \times \left(\frac{\text{Saturation y} \;/\; \text{Efficiency y}}{\text{Saturation base y} \;/\; \text{Efficiency base y}} \right)$$

$$\text{CoolEquipIndex} = \sum_{\text{Tech}} \text{Weight} \times \left(\frac{\text{Saturation y} \;/\; \text{Efficiency y}}{\text{Saturation base y} \;/\; \text{Efficiency base y}} \right)$$

$$\text{OtherEquipIndex} = \sum_{\text{Tech}} \text{Weight} \times \left(\frac{\text{Saturation y} \;/\; \text{Efficiency y}}{\text{Saturation base y} \;/\; \text{Efficiency base y}} \right)$$

Next, the **monthly usage multiplier or utilization variable** (HeatUse, CoolUse, OtherUse) are defined using economic and weather variables. A customer's monthly usage level is impacted by several factors, including weather, household size, income levels, electricity prices and the number of days in the billing cycle. The degree day variables serve to allocate the seasonal impacts of weather throughout the year, while the remaining variables serve to capture changes in the economy.

$$\text{HeatUse}_{y,m}$$

$$\left(\frac{\text{Price y, m}}{\text{Price base y, m}}\right)^{-.30} \times \left(\frac{\text{HH Income y, m}}{\text{HH Income base y, m}}\right)^{.30} \times \left(\frac{\text{HH Size y, m}}{\text{HH Size base y, m}}\right)^{.30} \times \left(\frac{\text{HDD y, m}}{\text{Normal HDD}}\right)$$

$$\text{CoolUse}_{y,m}$$

$$\left(\frac{\text{Price y, m}}{\text{Price base y, m}}\right)^{-.30} \times \left(\frac{\text{HH Income y, m}}{\text{HH Income base y, m}}\right)^{.30} \times \left(\frac{\text{HH Size y, m}}{\text{HH Size base y, m}}\right)^{.30} \times \left(\frac{\text{CDD y, m}}{\text{Normal CDD}}\right)$$

$$\text{OtherUse}_{y,m}$$

$$\left(\frac{\text{Price y, m}}{\text{Price base y, m}}\right)^{-.30} \times \left(\frac{\text{HH Income y, m}}{\text{HH Income base y, m}}\right)^{.30} \times \left(\frac{\text{HH Size y, m}}{\text{HH Size base y, m}}\right)^{.25} \times \left(\frac{\text{Billing Days y, m}}{\text{Billing Days base y, m}}\right)$$

The SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels and gives estimates of weather sensitivity that varies over time as well as estimate trend adjustments.

2. Commercial Energy Models:

Total Commercial energy sales include commercial sales plus temporary service sales (temporary poles on construction sites); therefore, two models are used to forecast total commercial energy sales.

a. Commercial Energy Model: The model framework for the commercial sector is the same as the residential model; it also has three major components and utilizes the SAE model framework. The differences lie in the type of end-use equipment and in the economic variables used. The end-use equipment variables are based on commercial appliance/equipment saturation and efficiency assumptions. The economic drivers in the commercial model are commercial productivity measured in terms of dollar output and the price of electricity for the commercial sector. The third component, weather variables, is the same as in the residential model.

b. Temporary Service Energy Model: The model is a subset of the total commercial sector and is a rather small percentage of the total commercial sector. Although small in nature, it is still a component that needs to be included. A simple regression model is used with the primary drivers being the construction sector's productivity and heating and cooling degree-days.

3. Industrial Energy Model (Non-Phosphate):

Non-phosphate industrial energy includes three rate classes that have been modeled individually: General Service, General Service Demand and General Service Large Demand.

a. The General Service Energy Model has two major components. Utilizing the SAE model framework, the first component, economic index variables, includes estimates for manufacturing output and the price of electricity in the industrial sector. The second component is a cooling degree-day variable. Unlike the previous models discussed, heating load does not impact the industrial sector.

b. The General Service Demand Energy Model is modeled like the General Service Energy Model.

c. The General Service Large Demand Customer Model is based on an Industrial Production Manufacturing Index and a cooling degree day variable.

4. Public Authority Sector Model:

Within this model, the equipment index is based on the same commercial equipment saturation and efficiency assumptions used in the commercial model. The economic component is based on government sector productivity and the price of electricity in this sector. Weather variables are consistent with the residential and commercial models.

5. Street & Highway Lighting Sector Model:

The street and highway lighting sector is not impacted by weather; therefore; it is a rather simple model and the SAE modeling approach does not apply. The model is a linear regression model where street & highway lighting energy consumption is a function of the number of billing days in the cycle, and the number of daylight hours in a day for each month.

The eight energy models described above plus an exogenous interruptible and phosphate forecast are added together to arrive at the total retail energy sales forecast.

In summary, the SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels, gives estimates of weather sensitivity that varies over time, as well as estimates trend adjustments.

4. Demand Multiregression Models

After the total retail energy sales forecast is complete, it is integrated into the peak demand model as an independent variable along with weather variables. The energy variable represents the long-term economic and appliance trend impacts. To stabilize the peak demand data series and improve model accuracy, the volatility of the phosphate load is removed. To further stabilize the data, the peak demand models project on a per customer basis.

The weather variables provide the monthly seasonality to the peaks. The weather variables used are heating and cooling degree-days for both the temperature at the time of the peak and the 24-hour average on the day of the peak. By incorporating both temperatures, the model is accounting for the fact that cold/heat buildup contributes to determining the peak day.

The non-phosphate per customer kW forecast is multiplied by the final customer forecast. This result is then aggregated with a phosphate coincident peak forecast to arrive at the final projected peak demand.

5. Phosphate Demand and Energy Analysis

Because Tampa Electric's phosphate customers are relatively few in number, the company's Commercial/Industrial Customer Service Department has obtained detailed knowledge of industry developments including:

1. knowledge of expansion and close-out plans;
2. familiarity with historical and projected trends;
3. personal contact with industry personnel;
4. governmental legislation;
5. familiarity with worldwide demand for phosphate products.

This department's familiarity with industry dynamics and their close working relationship with phosphate company representatives were used to form the basis for a survey of the phosphate customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecast is based. Further inputs are provided by the multiregression model's phosphate demand equations and discussions with industry experts.

6. Demand Side Management and Cogeneration Programs

Tampa Electric has developed conservation, load management and cogeneration programs to achieve five major objectives:

1. Defer expansion, particularly production plant construction.
2. Reduce marginal fuel cost by managing energy usage during higher fuel cost periods
3. Provide customers with some ability to control energy usage and decrease energy costs.
4. Pursue the cost-effective accomplishment of the Florida Public Service Commission (FPSC) ten-year demand and energy goals for the residential and commercial/industrial sectors.
5. Achieve the comprehensive energy policy objectives as required by the Florida Energy Efficiency Conservation Act.

The company's current Demand Side Management (DSM) plan contains a mix of proven, mature programs that focus on the market place demand for their specific offerings. The following is a list that briefly describes the company's programs:

1. Heating and Cooling - Encourages the installation of high-efficiency residential heating and cooling equipment.
2. Load Management - Reduces weather-sensitive heating, cooling, water heating and pool pump loads through a radio signal control mechanism. Commercial and industrial programs are offered. Although Tampa Electric's residential program is currently closed to new participants, the company had over 57,000 participating customers through December 31, 2006.
3. Energy Audits - The program is a "how to" information and analysis guide for customers. Five types of audits are available to Tampa Electric customers; three types are for residential class customers and two types for commercial/industrial customers.
4. Ceiling Insulation - An incentive program for existing residential structures which will help to supplement the cost of adding additional insulation.
5. Commercial Indoor Lighting - Encourages investment in more efficient lighting technologies within existing commercial facilities.
6. Standby Generator - A program designed to utilize the emergency generation capacity of commercial/industrial facilities in order to reduce weather sensitive peak demand.
7. Conservation Value - Encourages investments in measures that are not sanctioned by other commercial programs.
8. Duct Repair - An incentive program for existing homeowners which will help to supplement the cost of repairing leaky ductwork of central air–conditioning systems.
9. Cogeneration - A program whereby large industrial customers with waste heat or fuel resources may

install electric generating equipment, meet their own electrical requirements and/or sell their surplus to the company.

10. Commercial Cooling - Encourages the installation of high efficiency direct expansion commercial cooling equipment.
11. Energy Plus Homes - Encourages the construction of residential dwellings at efficiency levels greater than current Florida building code baseline practices.
12. Price Responsive Load Management (pilot) – A load management project designed to reduce weather sensitive peak loads by offering a multi-tiered rate structure as an incentive for participating customers to reduce their electric demand during high cost or critical periods of generation.

The programs listed above were developed to meet the FPSC demand and energy goals established in Docket No. 040033-EG, approved on August 9, 2004. The 2005 demand and energy savings achieved by conservation and load management programs are listed in Table III-1.

Tampa Electric developed a Monitoring and Evaluation (M&E) plan in response to requirements filed in Docket No. 941173-EG. The M&E plan was designed to effectively accomplish the required objective with prudent application of resources.

The M&E plan has as its focus two distinct areas: process evaluation and impact evaluation. Process evaluation examines how well a program has been implemented including the efficiency of delivery and customer satisfaction regarding the usefulness and quality of the services delivered. Impact evaluation is an evaluation of the change in demand and energy consumption achieved through program participation. The results of these evaluations give Tampa Electric insight into the direction that should be taken to refine delivery processes, program standards, and overall program cost-effectiveness.

Although Tampa Electric is exceeding its current DSM goals, the company is currently undertaking several steps to determine what, if any, additional conservation and load management offerings can be made available to its customers in an effort to further advance the five objectives previously stated. This effort is being driven by recent increased avoided generating unit and fuel costs. Specifically, Tampa Electric is systematically conducting the following evaluations:

1. Reviewing a full complement of residential and commercial DSM measures for cost-effectiveness and possible inclusion into a program offering to customers;
2. Utilizing M&E data to assist in the evaluation of all current programs to determine if incentive structures and program delivery mechanisms may be modified to secure additional customer participation;
3. Conducting an exhaustive review of DSM programs offered by other utilities in similar climate zones to determine their applicability in Tampa Electric's service area;
4. Exploring demand response as a viable commercial offering; and,
5. Gathering data from field personnel concerning energy consumption issues from the customer's perspective and determining the potential for cost-effective DSM solutions.

Tampa Electric's residential pilot program, Price Responsive Load Management, is a demand response program that has shown great promise for load shifting and energy conservation. The company is in the final phase of preparing to request Commission approval to offer the program on a permanent basis. It is anticipated the program offering will be available to customers by third quarter 2007.

Wholesale Load

Tampa Electric's firm long-term wholesale sales consist of five (5) sales contracts with the Cities of Wauchula, Fort Meade, St. Cloud, Progress Energy Florida and Reedy Creek Improvement District.

Since Tampa Electric's sales to Wauchula and Fort Meade will vary over time based on the strength of the local economies, a multiple regression approach similar to that used for forecasting Tampa Electric's retail load has been utilized. Under this methodology, two equations have been developed for each municipality for forecasting energy: 1) customer forecast and 2) average usage forecast. The peak

TABLE III-1
Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2005	4.2	4.0	105.0%	2.8	2.4	116.7%	7.7	7.0	110.0%
2006	8.2	6.7	122.4%	6.1	4.4	138.6%	16.3	12.6	129.4%

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2005	3.4	1.0	340.0%	4.3	2.1	204.8%	7.9	6.7	117.9%
2006	3.8	2.0	190.0%	5.8	4.4	131.8%	15.3	12.8	119.5%

Combined Total

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2005	7.6	5.0	152.0%	7.1	4.5	157.8%	15.6	13.7	113.9%
2006	12.0	8.7	137.9%	11.9	8.8	135.2%	31.6	25.4	124.4%

models for these two cities use sales forecast trend variables and heating and cooling degree variables as inputs.

Florida Municipal Power Agency will commence serving City of Fort Meade's electric load on January 1, 2009 and will include the city's load in its 2007 Ten-Year Site Plan. Tampa Electric will continue to serve the City of Fort Meade's electric load through December 31, 2008.

For the remaining wholesale customers, future sales for a given year are based on the specific terms of their contracts with Tampa Electric.

Base Case Forecast Assumptions

Retail Load

Numerous assumptions are inputs to the MetrixND models of which the more significant ones are listed below.

1. Population and Households;
2. Commercial, Industrial and Governmental Employment;
3. Commercial, Industrial and Governmental Output;
4. Real Household Income;
5. Price of Electricity;
6. Appliance Efficiency Standards; and
7. Weather.

1. Population and Households

The state population forecast is the starting point for developing the customer and energy projections. Both the University of Florida's Bureau of Economic and Business Research (BEBR) and Economy.com supply population projections for Hillsborough County and Florida. The population forecast is based upon the projections of BEBR in the short term and is a blend in the long term of BEBR and Economy.com. Over the next ten years (2007-2016) the average annual population growth rate in both Hillsborough County and Florida is expected to be 2%. In addition, Economy.com provides household data as an input to the residential average use model.

2. Commercial, Industrial and Governmental Employment

Commercial and industrial employment assumptions are utilized in computing the number of customers in their respective sectors. It is imperative that employment growth be consistent with the expected population expansion and unemployment levels. Over the next ten years, employment is assumed to rise at a 3% average annual rate. Economy.com supplies employment projections.

3. Commercial, Industrial and Governmental Output

In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy in their respective sectors. Over the next ten years, output for the entire employment sector is assumed to rise at a 4.8% average annual rate. Economy.com supplies output projections.

4. Real Household Income

Economy.com supplies the assumptions for Hillsborough County's real household income growth. During 2007-2016, real household income for Hillsborough County is expected to increase at a 1.6% average annual rate.

5. Price of Electricity

Forecasts for the price of electricity by customer class are supplied by Tampa Electric's Regulatory Department.

6. Appliance Efficiency Standards

Another factor influencing energy consumption is the movement toward more efficient appliances. The forces behind this development include market pressures for more energy-saving devices and the appliance efficiency standards enacted by the state and federal governments.

Also influencing energy consumption is the saturation levels of appliances. The saturation trend for heating appliances is increasing through time; however, overall electricity consumption actually declines over time as less efficient heating technologies (room heating and furnaces) are replaced with more efficient technologies (heat pumps). Similarly, cooling equipment saturation will continue to increase, but be offset by heat pump and central air conditioning efficiency gains.

Improvements in the efficiency of other non-weather related appliances also helps to lower electricity growth; however, any efficiency gains are offset by the increasing saturation trend of electronic equipment and appliances in households throughout the forecast period.

7. Weather

Since weather is the most difficult input to project, historical data is the major determinant in developing temperature profiles. For example, monthly profiles used in calculating energy consumption are based on twenty years of historical data. In addition, the temperature profiles used in projecting the winter and summer system peak are based on an examination of the minimum and maximum temperatures for the past twenty years plus the temperatures on peak days for the past twenty years.

In summary, despite the high saturation of electric appliances, increased appliance and equipment efficiencies will slow residential usage making them less sensitive to changes in temperature through time. However, economic conditions such as the decreasing real price of electricity and the increasing household income will mitigate any decline in consumption and actually increase overall energy consumption.

High and Low Scenario Focus

The base case scenario is tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy scenarios represent alternatives to the company's base case outlook. The high scenario represents more optimistic economic conditions in the areas of customers, employment, and income. The low band represents a less optimistic scenario in the same areas. Compared to the base case, the expected customer and economic growth rates are 0.5% higher in the high scenario and 0.5% lower in the low scenario.

History and Forecast of Energy Use

A history and forecast of energy consumption by customer classification are shown in Schedules 2.1 - 2.3.

Retail Energy

For 2007-2016, retail energy sales are projected to rise at a 2.8% annual rate. The major contributor to growth is the residential category, increasing at an annual rate of 3.1%.

Wholesale Energy

Wholesale energy sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, and Reedy Creek are expected to be 682 GWH in 2007. In 2011, sales drop substantially to 285 GWH and continue to decline to 137 GWH in 2013 and 78 in 2014.

History and Forecast of Peak Loads

Historical and base scenario forecasts of peak loads for the summer and winter seasons are presented in Schedules 3.1 and 3.2, respectively. For the 2007-2016 period, Tampa Electric's base case retail firm peak demand for winter and summer are expected to advance at annual rates of 3.1% and 3.0% respectively.

Forecast of Facilities Requirements

The proposed generating facility additions and changes shown in Schedule 8 integrate DSM programs and generating resources to provide economical, reliable service to Tampa Electric's customers. Various energy resource plan alternatives comprised of a mixture of generating technologies, purchased power, and cost-effective DSM programs are developed to determine this plan. These alternatives are combined with existing supply resources and analyzed to determine the energy resource option which best meets Tampa Electric's future system demand and energy requirements. A detailed discussion of Tampa Electric's integrated resource planning process is included in Chapter V.

The results of the integrated resource planning process provide Tampa Electric with a plan that is cost-effective while maintaining system reliability, balancing engineering concerns and other issues. To meet the expected system demand and energy requirements over the next ten years both peaking and base load capacity is needed. The peaking capacity need will be met by self-build and peaking power purchases throughout the ten year planning period. The base load capacity needs will be met by building one integrated coal gasification combined cycle unit planned for 2013. The operating and cost parameters associated with the capacity additions resulting from the analysis are shown in Schedule 8.

As the construction start dates for each scheduled unit approaches, Tampa Electric will continue to look for competitive purchased power agreements that may replace or delay the planned unit additions. Such alternatives will be considered, if they are better suited to achieving the overall objective of providing reliable power in the most cost-effective manner. Assumptions and information that impact the plan are discussed in the following sections and in Chapter V.

In the fall of 2006 Tampa Electric solicited offers for peaking generation as an alternative to scheduled units through a Request for Proposal (RFP). The overriding objective of this RFP was to solicit bids for competitive resources that provide Tampa Electric with reliable and cost-effective capacity alternatives to satisfy its projected capacity requirements. The RFP was open to products within the Florida Reliability Coordinating Council (FRCC) North American Electric Reliability Council (NERC) Region as well as products originating outside of the FRCC given that the seller obtained the appropriate firm transmission service(s) to assure delivery. Tampa Electric requested proposals from all potential suppliers capable of satisfying the conditions of the RFP, including other electric utilities, power marketers, exempt wholesale generators, independent power producers, and qualifying facilities.

Through the RFP, Tampa Electric Company was seeking power supply proposals to meet its requirements for electric generating capacity and associated energy commencing on January 1, 2009, which provided the best value to its customers based on cost, reliability, and flexibility. In the RFP, Tampa Electric solicited proposals for peaking capacity and associated energy in the amounts, and during the time periods, described in the table below:

COMMENCEMENT DATE	REQUESTED CAPACITY AMOUNTS (MW)	CUMULATIVE CAPACITY AMOUNTS REQUESTED (MW)
January 1, 2009	Up to 150	150
January 1, 2010	Up to 175	325
May 1, 2011	Up to 235	560
May 1, 2012 and beyond	Up to 170	730

Tampa Electric received numerous offers for both existing and new generation. The offers were first prioritized based on their economic viability to offset or delay Tampa Electric self build generation. Factors used in determining this viability included capacity charge, fuel costs, variable and fixed operations and maintenance costs, startup costs and other charges associated with the offers. Several of the highest ranked offers were determined to be potentially cost effective alternatives to Tampa Electric self build options. Tampa Electric conducted a detailed cost analysis for each of these highest ranked offers using PROMOD, an economic dispatch model, in conjunction with an incremental capital revenue requirement calculation. Tampa Electric found several alternatives that demonstrated a benefit to Tampa Electric's customers through a combination of fuel savings and the offset or delay of Tampa Electric's next scheduled self build unit(s). Tampa Electric is currently in negotiation with these parties with the intent to complete purchased power agreements for the generation. The need expected to be filled as a result of this RFP is approximately 168 MW in the winter and 158 MW in the summer starting 2009 through 2011 and an additional 168 MW in the winter and 158 MW in the summer starting in May 1, 2011. Tampa Electric expects to complete negotiation of purchase power agreements during the second quarter of 2007.

IGCC Technology

In 1996, Tampa Electric began commercial operation of the Polk Power Station, originally a 260-megawatt Integrated Gasification Combined Cycle power plant. Operational improvements developed by Tampa Electric and the cost of fuel make the Polk IGCC Unit the most economical unit on Tampa Electric's system. Polk Unit 1 has inherently low environmental emissions due to the IGCC technology. Polk Unit 6 will have even lower emissions than Polk 1 and will also be designed to be carbon capture ready. Because Polk Unit 1 has established IGCC as a clean, economical and reliable technology, IGCC technology is the logical candidate for future baseload needs. In addition to these factors, fuel diversity is also an important consideration for future baseload generation. Tampa Electric has recognized and responded to federal and state fuel diversity concerns. Both the federal government through the Energy Policy Act of 2005 and the state of Florida through the 2006 Florida Energy Plan have recognized the benefits of fuel diversity and advancing electric generation technology. One method by which the federal government has addressed concerns regarding fuel diversity has been to encourage the development of advanced clean-coal technologies. In 2006, the Internal Revenue Service and U. S. Department of Energy awarded Tampa Electric $133 million in tax credits for a proposed 630 megawatt IGCC project to be built at the company's Polk Power Station.

Tampa Electric's 2006 fuel mix on a capacity basis was 53% Coal/Pet Coke, 44% Natural Gas related resources, and 0.3% Oil. If Tampa Electric future generation needs were met with only natural gas fuel generation the fuel mix in 2013 would be 45% Coal/Pet Coke, 54% Natural Gas related resources, and 0.3% Oil. This would represent an increasing reliance on natural gas for the production of electricity. Although natural gas generation offers relatively low capital cost, high efficiency and good environmental performance, continued capacity expansion relying only on this technology would put Tampa Electric's electric generation at significant exposure to those risks inherent with the natural gas commodity. Some of the risks include price volatility, delivery disruptions and long term price exposure. In contrast, Tampa Electric's 2013 proposed expansion plan fuel mix is 64% Coal/Pet Coke, 35% Natural Gas related resources, and 0.2% Oil. This mix reflects a more balanced fuel mix and will result in reduced exposure and less reliance on a single commodity.

Cogeneration

Tampa Electric plans for 427 MW of cogeneration capacity operating in its service area in 2007. Self-service capacity of 212 MW is used by cogenerators to serve internal load requirements, 65 MW are purchased by Tampa Electric on a firm contract basis, and 14 MW are purchased on a non-firm, as-available basis. The remaining 136 MW of cogeneration capacity is forecasted to other utilities and is exported out of Tampa Electric's system.

Fuel Requirements

A forecast of fuel requirements and energy sources is shown in Schedule 5, Schedule 6.1 and Schedule 6.2.

Tampa Electric currently has a generation portfolio consisting of coal and natural gas for its generating requirements. Tampa Electric has firm transportation contracts with the Florida Gas Transmission Company (FGT) and Gulfstream Natural Gas System LLC for delivery of natural gas to the Bayside and Polk Units. As shown in Schedule 6.2, in 2007 coal and pet coke will fuel 50% of net energy for load and natural gas will fuel 37%. Less than one percent of net energy for load will be fueled by oil at the Phillips plant and other combustion turbines. The remaining net energy for load is met by purchases from non-utility generators and net interchange.

Environmental Considerations

An agreement between the Florida Department of Environmental Protection (DEP) and Tampa Electric produced a comprehensive emissions reduction plan delineated in a Consent Final Judgment (CFJ), which was finalized with the DEP on December 6, 1999. Approximately one year later, on February 29, 2000, Tampa Electric reached a similar agreement with the U.S. Environmental Protection Agency (EPA) in a Consent Decree (CD). Collectively, the CFJ and CD are referred to as the "Agreements". The efforts to reduce emissions from the company's facilities began long before the agreements. Since 1998, Tampa Electric has to date reduced annual sulfur dioxides (SO_2), nitrogen oxides (NOx), and particulate matter (PM) emissions from our facilities by 161,000 tons, 41,000 tons, and 4,000 tons, respectively.

Reductions in SO_2 emissions were primarily accomplished through the installation of flue gas desulfurization (scrubber) systems on Big Bend Units 1 and 2 in 1999. Big Bend Unit 3 was integrated with Big Bend Unit 4's existing scrubber in 1995. Currently, the scrubbers at Big Bend station remove between 93% and 95% of the SO_2 emissions from the flue gas streams. In addition, reductions in NOx have been accomplished through combustion tuning and optimization projects at Big Bend Station and the repowering of Gannon Station to H.L. Culbreath Bayside Power Station.

Reductions in particulate matter were accomplished through the use of electrostatic precipitators, which remove more than 99.9% of the PM generated during the combustion process.

The repowering of Gannon Station to H.L. Culbreath Bayside Power Station resulted in significant reduction in emissions of all pollutant types. Tampa Electric's decision to install additional NOx emissions controls on all Big Bend Station Units by May of 2010 will result in the further reduction of emissions. Selective Catalytic Reduction (SCR) will be the control technology used to reduce Big Bend Station NOx emissions. The first unit scheduled to have an SCR installed by June 1, 2007 is Unit 4. Subsequently, the other units will be compliant by May 1 of 2008, 2009 and 2010. By 2010, these projects are expected to result in 62,000 tons per year of additional NOx reduction. In total, Tampa Electric's emission reduction initiatives will result in the reduction of SO_2, NOx and PM emissions by 89%, 90%, and 72%, respectively, below 1998 levels. With these improvements in place, Tampa Electric's facilities will meet the same standards required of newer power generating facilities and significantly enhance the quality of the air in the community. As a result of all its already completed emission reduction actions and upon completion of planned controls, Tampa Electric will have achieved emission reduction levels contained in the Clean Air Interstate Rule (CAIR) Phase I requirements, the Clean Air Mercury Rule (CAMR) Phase I requirements and be positioned for other potential future emission control requirements.

Interchange Sales and Purchases

Tampa Electric's long-term firm sale agreements include Progress Energy Florida for 70 MW and Reedy Creek Improvement District for 75 MW as well as the cities of Ft. Meade for 12 MW, St. Cloud for 15 MW and Wauchula for 15 MW. Tampa Electric also has a firm sales agreement to New Smyrna Beach of 10 MW for January 2006 through December 31, 2007.

Tampa Electric has a long-term purchased power contract for capacity and energy from the Hardee Power Station owned by Invenergy. The contract term is January 1, 1993 through December 31, 2012. The contract involves a shared-capacity agreement with Seminole Electric Cooperative (SEC), whereby Tampa Electric plans for the full net capability (353 MW winter and 287 MW summer) of the Hardee Power Station during those times when SEC plans for the Seminole Units 1 and 2 and the SEC Crystal River

Unit 3 allocation to be available for operation, and reduced availability during times when Seminole Units 1 and 2 are derated or unavailable due to planned maintenance. Under the existing contract Tampa Electric also has the right to purchase an additional 88 MW winter and 69 MW summer of firm non-shared capacity from the Hardee Power Station.

Tampa Electric also entered into a firm purchased power agreement with Progress Energy Florida for 50 MW from January 1, 2006 through March 31, 2007; the contract was extended through November 31, 2007 at an increase of 25 MW for a total of 75 MW. For the winter of 2007, Tampa Electric has purchased power agreements of 50 MW and 40 MW with Cargill Power Markets and New Hope Power Partnership, respectively. In addition, Tampa Electric has an agreement with Calpine Energy Services for 170 MW from May 1, 2006 through April 30, 2011. Tampa Electric has completed a term sheet for the purchase of 115 MW from Pasco Cogen for the period January 1, 2009 to December 31, 2018.

As a result of an existing purchased power agreement ending in 2011, Tampa Electric has a 170 MW need extending through 2016. Additionally, in the summer of 2011 through 2016 Tampa Electric has a need of 160 MW as well as spot purchases of 70 MW and 25 MW during the summers of 2012 and 2016, respectively. In the winters of 2012 and 2013, Tampa Electric has a need of 180 MW and 172 MW extending throughout the study period.

Tampa Electric determined that it has a capacity need during the winters of 2008, 2009 and 2010. The capacity need is 135 MW for 2008, 155 MW for 2009 and 170 MW for 2010. This capacity need is for the completion of the SCR system installations by the required Consent Decree. Big Bend units 1, 2, and 3 will be down in consecutive years for the scheduled work from January through mid-April in 2008, 2009 and 2010.

As discussed earlier in this section, Tampa Electric will seek to satisfy these capacity needs for the given years by contracting power from one or more entities. Inquiries have begun to locate potential sources of capacity. Tampa Electric will look to sign agreement(s) that provide cost-effective alternative(s) to satisfy the projected requirements.

The wholesale power sales and purchases are included in Schedules 3.1, 3.2, 3.3, 4, 5, 6.1, 7.1, and 7.2.

Schedule 7.1

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2007	4,281	601	10	65	4,937	4,057	880	22%	0	880	22%
2008	4,332	684	0	65	5,081	4,176	905	22%	0	905	22%
2009	4,332	799	0	65	5,196	4,299	897	21%	0	897	21%
2010	4,461	799	0	42	5,302	4,421	881	20%	0	881	20%
2011	4,461	959	0	42	5,462	4,472	990	22%	0	990	22%
2012	4,461	1,026	0	23	5,510	4,599	911	20%	0	911	20%
2013	5,066	600	0	23	5,689	4,720	969	21%	0	969	21%
2014	5,242	600	0	23	5,865	4,841	1,024	21%	0	1,024	21%
2015	5,389	600	0	23	6,012	4,991	1,021	20%	0	1,021	20%
2016	5,565	625	0	0	6,190	5,144	1,046	20%	0	1,046	20%

NOTE:

1. Capacity import includes firm purchase power agreements with Invenergy of 356 MW from 2006 through 2012, 50 MW through March,2007 increasing to 75 MW through November,2007 from Progress Energy Florida and 170 MW from Calpine from May 2006 through April 2011. Pasco Cogen for 115 MW from 2009 through 2018. TEC has issued a Request for Proposal(RFP) for peaking power from 2008 through 2011 for 158 MW in the summer. Unspecified purchased power of 160 MW is needed beginning in the summer of 2011 through 2016 as well as a purchase of 155 MW beginning in the summer of 2012 through 2016. Unspecified purchased power of 170 MW is needed beginning in the summer of 2011 through 2016 as well as spot market purchases of 70 MW and 25 MW for the summers of 2012 and 2016.
2. The QF column accounts for cogeneration that will be purchased under firm contracts.
3. Big Bend CT 1, 2, and 3 will be retired January 1, 2015.

Schedule 7.2

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2006-07	4,276	844	10	65	5,175	4,233	942	22%	0	942	22%
2007-08	4,686	914	0	65	5,665	4,365	1,300	30%	423	867	20%
2008-09	4,686	1,049	0	65	5,800	4,496	1,304	29%	401	913	20%
2009-10	4,827	1,064	0	65	5,956	4,628	1,328	29%	401	917	20%
2010-11	4,827	894	0	42	5,763	4,756	1,007	21%	0	1,007	21%
2011-12	4,827	1,074	0	23	5,924	4,817	1,107	23%	0	1,107	23%
2012-13	5,457	637	0	23	6,117	4,941	1,176	24%	0	1,176	24%
2013-14	5,457	637	0	23	6,117	5,064	1,053	21%	0	1,053	21%
2014-15	5,610	637	0	23	6,270	5,220	1,050	20%	0	1,050	20%
2015-16	5,804	637	0	0	6,441	5,380	1,061	20%	0	1,061	20%

NOTE:

1. Capacity import includes firm purchase power agreements with Invenergy of 441 MW from 2006 through 2012, Progress Energy Florida of 50 MW through March, 2007 increasing to 75 MW through November,2007 and Calpine of 170 MW from May 2006 through April 2011. Winter of 2007 purchases of 50 MW and 40 MW from Cargill and New Hope Power Partnership. Unspecified purchased power of 135 MW is expected to be needed for the installation of the Selective Catalytic Reduction (SCR) equipment on Big Bend 3 in 2008, a purchase of 155 MW in 2009 for Big Bend 2 and a purchase of 170 MW for Big Bend 1 in 2010. Pasco Cogen for 115 MW from 2009 through 2018. TEC has issued a Request for Proposal(RFP) for peaking power from 2008 through 2012 for 168 MW in the winter. Unspecified purchase power of 180 MW is needed in the winter of 2012 through 2016. Unspecified purchase power of 172 MW is needed in the winter of 2013 through 2016.
2. The QF column accounts for cogeneration that will be purchased under firm contracts.
3. Big Bend CT 1, 2, and 3 will be retired January 1, 2015.

* Values may be affected due to rounding.

Schedule 8

Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Trans.		Const.	Commercial	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Start Mo/Yr	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate kW	Summer MW	Winter MW	Status
Future CT*	1	unknown	GT	NG	DFO	PL	TK	1/09	1/10	unknown	unknown	43	47	P
Future CT*	2	unknown	GT	NG	NA	PL	NA	1/09	1/10	unknown	unknown	43	47	P
Future CT*	3	unknown	GT	NG	NA	PL	NA	1/09	1/10	unknown	unknown	43	47	P
Polk IGCC	6	Polk	IGCC	BIT	NG	WA	PL	1/09	1/13	unknown	unknown	605	630	P
Future CT	4	unknown	GT	NG	NA	PL	NA	1/13	5/14	unknown	unknown	88	97	P
Future CT	5	unknown	GT	NG	NA	PL	NA	1/13	5/14	unknown	unknown	88	97	P
Future CT	6	unknown	GT	NG	NA	PL	NA	5/13	1/15	unknown	unknown	88	97	P
Future CT	7	unknown	GT	NG	NA	PL	NA	1/14	5/15	unknown	unknown	88	97	P
Future CT	8	unknown	GT	NG	NA	PL	NA	1/14	5/15	unknown	unknown	88	97	P
Future CT	9	unknown	GT	NG	NA	PL	NA	1/15	5/16	unknown	unknown	88	97	P
Future CT	10	unknown	GT	NG	NA	PL	NA	1/15	5/16	unknown	unknown	88	97	P

* The future CT additions slated for 2010 are GE LM6000 technology all other future CT expansion are GE LMS 100 technology.

SCHEDULE 9
(Page 1 of 11)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 1
(2)	CAPACITY	
	A. SUMMER	43
	B. WINTER	47
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2009
	B. COMMERCIAL IN-SERVICE DATE	JAN 2010
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE FUEL OIL
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	0.8
	FORCED OUTAGE RATE (FOR)	4.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94.0
	RESULTING CAPACITY FACTOR (2010)	4.8%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,792 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	760.51
	DIRECT CONSTRUCTION COST ($/kW)	674.12
	AFUDC AMOUNT ($/kW)	63.49
	ESCALATION ($/kW)	22.90
	FIXED O&M ($/kW – Yr)	9.50
	VARIABLE O&M ($/MWH)	2.91
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR.

SCHEDULE 9
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STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 2
(2)	CAPACITY	
	A. SUMMER	43
	B. WINTER	47
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2009
	B. COMMERCIAL IN-SERVICE DATE	JAN 2010
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	0.8
	FORCED OUTAGE RATE (FOR)	4.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94.0
	RESULTING CAPACITY FACTOR (2010)	4.8%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,792 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	760.51
	DIRECT CONSTRUCTION COST ($/kW)	674.12
	AFUDC AMOUNT ($/kW)	63.49
	ESCALATION ($/kW)	22.90
	FIXED O&M ($/kW – Yr)	9.50
	VARIABLE O&M ($/MWH)	2.91
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR.

SCHEDULE 9
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STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 3
(2)	CAPACITY	
	A. SUMMER	43
	B. WINTER	47
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START-DATE	JAN 2009
	B. COMMERCIAL IN-SERVICE DATE	JAN 2010
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	UNDETERMINED
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	0.8
	FORCED OUTAGE RATE (FOR)	4.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94.0
	RESULTING CAPACITY FACTOR (2010)	4.8%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,792 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	760.51
	DIRECT CONSTRUCTION COST ($/kW)	674.12
	AFUDC AMOUNT ($/kW)	63.49
	ESCALATION ($/kW)	22.90
	FIXED O&M ($/kW – Yr)	9.50
	VARIABLE O&M ($/MWH)	2.91
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 4 of 11)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE IGCC
(2)	CAPACITY	
	A. SUMMER	605
	B. WINTER	630
(3)	TECHNOLOGY TYPE	INTERGRATED COAL GASIFICATION COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2009
	B. COMMERCIAL IN-SERVICE DATE	JAN 2013
(5)	FUEL	
	A. PRIMARY FUEL	COAL / PETCOKE
	B. ALTERNATE FUEL	NATURAL GAS
(6)	AIR POLLUTION CONTROL STRATEGY	SYNGAS SATURATION DILUENT NITROGEN
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	7.4
	FORCED OUTAGE RATE (FOR)	5.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	85.1
	RESULTING CAPACITY FACTOR (2013)	88.5%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,304 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)[2]	3,180.30
	DIRECT CONSTRUCTION COST ($/kW)[2]	2,555.56
	AFUDC AMOUNT ($/kW)[2]	375.41
	ESCALATION ($/kW)	249.34
	FIXED O&M ($/kW – Yr)	37.68
	VARIABLE O&M ($/MWH)	0.83
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR.

2 PRELIMINARY COST ESTIMATE SUBJECT TO CHANGE BASED ON OVERNIGHT CONSTRUCTION COST $1.6 BILLION

SCHEDULE 9
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STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 4
(2)	CAPACITY	
	A. SUMMER	88
	B. WINTER	97
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2013
	B. COMMERCIAL IN-SERVICE DATE	MAY 2014
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2014)	7.2%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,164 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	770.27
	DIRECT CONSTRUCTION COST ($/kW)	618.55
	AFUDC AMOUNT ($/kW)	64.31
	ESCALATION ($/kW)	87.40
	FIXED O&M ($/kW – Yr)	4.34
	VARIABLE O&M ($/MWH)	3.18
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR.

SCHEDULE 9
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STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

((1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 5
(2)	CAPACITY	
	A. SUMMER	88
	B. WINTER	97
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2013
	B. COMMERCIAL IN-SERVICE DATE	MAY 2014
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2014)	7.2%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,164 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	770.27
	DIRECT CONSTRUCTION COST ($/kW)	618.55
	AFUDC AMOUNT ($/kW)	64.31
	ESCALATION ($/kW)	87.40
	FIXED O&M ($/kW – Yr)	4.34
	VARIABLE O&M ($/MWH)	3.18
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR.

SCHEDULE 9
(Page 7 of 11)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 6
(2)	CAPACITY	
	A. SUMMER	88
	B. WINTER	97
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	MAY 2013
	B. COMMERCIAL IN-SERVICE DATE	JAN 2015
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2015)	6.5%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,164 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	789.53
	DIRECT CONSTRUCTION COST ($/kW)	618.55
	AFUDC AMOUNT ($/kW)	65.92
	ESCALATION ($/kW)	105.05
	FIXED O&M ($/kW – Yr)	4.44
	VARIABLE O&M ($/MWH)	3.26
	K FACTOR	1.5983

1 *BASED ON IN-SERVICE YEAR*

SCHEDULE 9
(Page 8 of 11)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 7
(2)	CAPACITY	
	A. SUMMER	88
	B. WINTER	97
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2014
	B. COMMERCIAL IN-SERVICE DATE	MAY 2015
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2015)	6.0%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,164 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	789.53
	DIRECT CONSTRUCTION COST ($/kW)	618.55
	AFUDC AMOUNT ($/kW)	65.92
	ESCALATION ($/kW)	105.05
	FIXED O&M ($/kW – Yr)	4.44
	VARIABLE O&M ($/MWH)	3.26
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR

SCHEDULE 9
(Page 9 of 11)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 8
(2)	CAPACITY	
	A. SUMMER	88
	B. WINTER	97
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2014
	B. COMMERCIAL IN-SERVICE DATE	MAY 2015
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2015)	6.0%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,164 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	789.53
	DIRECT CONSTRUCTION COST ($/kW)	618.55
	AFUDC AMOUNT ($/kW)	65.92
	ESCALATION ($/kW)	105.05
	FIXED O&M ($/kW – Yr)	4.44
	VARIABLE O&M ($/MWH)	3.26
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR

SCHEDULE 9
(Page 10 of 11)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 9
(2)	CAPACITY	
	A. SUMMER	88
	B. WINTER	97
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2015
	B. COMMERCIAL IN-SERVICE DATE	MAY 2016
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2016)	5.6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,164 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	809.27
	DIRECT CONSTRUCTION COST ($/kW)	618.55
	AFUDC AMOUNT ($/kW)	67.57
	ESCALATION ($/kW)	123.15
	FIXED O&M ($/kW – Yr)	4.54
	VARIABLE O&M ($/MWH)	3.33
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR

SCHEDULE 9
(Page 11 of 11)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE CT 10
(2)	CAPACITY	
	A. SUMMER	88
	B. WINTER	97
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2015
	B. COMMERCIAL IN-SERVICE DATE	MAY 2016
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	N/A
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOX BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.1
	FORCED OUTAGE RATE (FOR)	1.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	96.9
	RESULTING CAPACITY FACTOR (2016)	5.6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) 1	9,164 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	809.27
	DIRECT CONSTRUCTION COST ($/kW)	618.55
	AFUDC AMOUNT ($/kW)	67.57
	ESCALATION ($/kW)	123.15
	FIXED O&M ($/kW – Yr)	4.54
	VARIABLE O&M ($/MWH)	3.33
	K FACTOR	1.5983

1 BASED ON IN-SERVICE YEAR

Schedule 10

Status Report and Specifications of Proposed Directly Associated Transmission Lines

POINT OF ORIGIN AND TERMINATION	NUMBER OF CIRCUITS	RIGHT-OF-WAY	CIRCUIT LENGTH	VOLTAGE	ANTICIPATED IN-SERVICE DATE	ANTICIPATED CAPITAL INVESTMENT	SUBSTATIONS	PARTICIPATION WITH OTHER UTILITIES
Gannon	1	No new ROW required	0.1 mi	230kV	Summer 2009	$6.8 million	New 230/69kV transformer at Gannon	None
Pebbledale to Willow Oak	1	Possible road ROW required	9.0 mi	230kV	Summer 2009	$20 million	New 230/69kV Substation at Willow Oak	None
Davis to Wheeler	1	Possible ROW required	12.3 mi	230kV	Summer 2010	$30 million	Davis - new 230kV switching station & 230/69kV transformer at Wheeler	None
Lake Tarpon/Sheldon to Double Branch	1	Possible road ROW required	1.4 mi	230kV	Summer 2011	$4.5 million	New 230/69kV transformer at Double Branch	PEF
Lake Agnes to Gifford	1	New ROW required.	13.1 mi.	230kV	Summer 2011	$23.5 million	No new Tampa Electric substations	PEF
Clearview to Himes	1	Possible road ROW required	6.1 mi.	138kV	Summer 2012	$10 million	New 138kV ring-bus and 2nd 138/69kV transformer at Himes	None
Willow Oak to Wheeler Road	1	Possible road ROW required	17.1 mi	230kV	Summer 2012	$30 million	Wheeler Road – complete 230kV Ring Bus	None
Polk to Hardee (2)	1	No new right of way required	9.4 mi	230kV	Summer 2012	$7.1 million	No new substations	SEC
Davis to Dale Mabry	1	No new right of way required	14.0 mi	230kV	Summer 2012	$26 million	Dale Mabry 230kV Ring Bus	None
Dale Mabry to Denham East	1	Possible road ROW required	5.7 mi	230kV	Summer 2012	$10 million	No new substations	PEF

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chapter 5

Other Planning Assumptions and Information

Transmission Constraints and Impacts

Based on a variety of assessments and sensitivity studies of the Tampa Electric transmission system using year 2006 Florida Reliability Coordinating Council (FRCC) databank models, no transmission constraints that violate the criteria stated in the Generation and Transmission Reliability Criteria section of this document were identified in these studies.

Expansion Plan Economics and Fuel Forecast

The overall economics and cost-effectiveness of the plan were analyzed using Tampa Electric's Integrated Resource Planning process. As part of this process, Tampa Electric evaluated various planning and operating alternatives to current operations, with objectives including meeting compliance requirements in the most cost-effective and reliable manner, maximizing operational flexibility and minimizing total costs.

Early in the study process, many alternatives were screened on a qualitative and quantitative basis to determine those alternatives that were the most feasible overall. Those alternatives that failed to meet the qualitative and quantitative considerations were eliminated. This phase of the study resulted in a set of feasible alternatives that were considered in a more detailed economic analysis.

Fuel commodity price forecasting for the base case is derived through analysis of historical and current prices combined with price forecasts obtained from various consultants and agencies. These sources include the New York Mercantile Exchange, Energy Information Administration, Hill & Associates, PIRA Energy Group, Coal Daily, Inside FERC and Platt's Oilgram.

High and low fuel price projections represent alternative forecasts to the company's base case outlook. The high and low price projections are defined by natural gas and oil prices varying 35% above or below the base case. The high and low price projections represent the implied volatility of gas prices used in the base forecast.

Only base case forecasts are prepared for coal fuels because of the fuels' relatively low price volatility. Only a base case forecast for oil is utilized because oil comprises a very small component of total system generation.

Generating Unit Performance Assumptions

Tampa Electric's generating unit performance assumptions are used to evaluate long-range system operating costs associated with particular generation expansion plans. Generating units are characterized by several different performance parameters. These parameters include capacity, heat rate, unit derations, planned maintenance weeks, and unplanned outage rates. The unit performance projections are based on historical data trends, engineering judgement, time since last planned outage, and recent equipment performance. The first five years of planned outages are based on a forecasted outage schedule, and the planned outages for the balance of the years are based on an average of the first five years.

The five-year forecasted outage schedule is based on unit-specific maintenance needs, material lead-time, labor availability, and the need to supply our customers with power in the most economical manner. Unplanned outage rate projections are based on an average of three years of historical data adjusted, if necessary, to account for current unit conditions.

Financial Assumptions

Tampa Electric makes numerous financial assumptions as part of the preparation for its Ten-Year Site Plan process. These assumptions are based on the current financial status of the company, the market for securities, and the best available forecast of future conditions. The primary financial assumptions include the FPSC-approved Allowance for Funds Used During Construction (AFUDC) rate, capitalization ratios, financing cost rates, tax rates, and FPSC-approved depreciation rates.

- Per the Florida Administrative Code, an amount for

AFUDC is recorded by the company during the construction phase of each capital project. This rate is set by the FPSC and represents the cost of money invested in the applicable project while it is under construction. This cost is capitalized, becomes part of the project investment, and is recovered over the life of the asset. The AFUDC rate assumed in the Ten-Year Site Plan represents the company's currently approved AFUDC rate.

- The capitalization ratios represent the percentages of incremental long-term capital that are expected to be issued to finance the capital projects identified in the Ten-Year Site Plan.
- The financing cost rates reflect the incremental cost of capital associated with each of the sources of long-term financing.
- Tax rates include federal income tax, state income tax, and miscellaneous taxes including property tax.
- Depreciation represents the annual cost to amortize the total original investment in a plant over its useful life less net salvage value. This provides for the recovery of plant investment. The assumed book life for each capital project within the Ten-Year Site Plan represents the average expected life for that type of investment.

Integrated Resource Planning Process

Tampa Electric's Integrated Resource Planning process was designed to evaluate demand side and supply side resources on a fair and consistent basis to satisfy future energy requirements in a cost-effective and reliable manner, while considering the interests of utility customers and shareholders.

The process incorporates a reliability analysis to determine timing of future needs and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. Initially, a demand and energy forecast, which excludes incremental DSM programs, is developed. Then a supply plan based on the system requirements, which excludes incremental DSM, is developed. This interim supply plan becomes the basis for potential avoided unit(s) in a comprehensive cost-effective analysis of the DSM programs. Once the cost-effective DSM programs are determined, the system demand and energy requirements are revised to include the effects of these programs on reducing system peak and energy requirements. The process is repeated to incorporate the incremental DSM programs and supply side resources.

The cost-effectiveness of DSM programs is based on the following standard Commission tests: the Rate Impact Measure (RIM), the Total Resource Cost (TRC), and the Participants Tests. Using the FPSC's standard cost-effectiveness methodology, each measure is evaluated based on different marketing and incentive assumptions. Utility plant avoidance assumptions for generation, transmission, and distribution are used in this analysis. All measures that pass the RIM, TRC, and Participants Tests in the DSM analysis are considered for utility program adoption. Each adopted measure is quantified into annual kW/kWh savings and is reflected in the demand and energy forecast. Measures with the highest RIM values are generally adopted first. Tampa Electric evaluates DSM measures using a spreadsheet that comports with Rule 25-17.008, F.A.C., and the FPSC's prescribed cost-effectiveness methodology.

Generating resources to be considered are determined through an alternative technology screening analysis, which is designed to determine the economic viability of a wide range of generating technologies for the Tampa Electric service area.

The technologies that pass the screening are included in a supply side analysis, which examines various supply side alternatives for meeting future capacity requirements.

Tampa Electric uses the PROVIEW module of STRATEGIST, a computer model developed by New Energy Associates, to evaluate the supply side resources. PROVIEW uses a dynamic programming approach to develop an estimate of the timing and type of capacity additions which would most economically meet the system demand and energy requirements. Dynamic programming compares all feasible combinations of generating unit additions, which satisfy the specified reliability criteria, and determines the schedule of additions that have the lowest revenue requirements. The model uses production costing analysis and incremental capital and O&M expenses to project the revenue requirements and rank each plan.

A detailed cost analysis for each of the top ranked resource plans is performed using the PROMOD economic dispatch model in conjunction with an incremental capital revenue requirement calculation. The capital expenditures associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources on our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative plan.

Strategic Concerns

Strategic concerns affect the type, capacity, and/or timing of future generation resource requirements. Concerns such as competitive pressures, environmental legislation, and plan acceptance are not easily quantified. These strategic concerns are considered within the Integrated Resource Planning process to ensure that an economically viable expansion plan is selected which has the flexibility for the company to respond to future technological and economic changes. The resulting expansion plan may include self-build generation, market purchase options or other viable supply and demand-side alternatives.

The results of the Integrated Resource Planning process provide Tampa Electric with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment. The new capacity additions are shown in Schedule 8. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, Tampa Electric is planning the addition of combustion turbines, Polk Unit 6 IGCC, and economical market purchases. For the purposes of this study, Big Bend CT Units 1 through 3 are assumed to be retired in January 2015.

As the scheduled SCR outages and construction outages for the new units approach, Tampa Electric will continue to look for competitive purchase power agreements that may replace or delay the scheduled new units. Such alternatives would be considered if better suited to the overall objective of providing reliable power in the most cost effective manner.

Generation and Transmission Reliability Criteria

Generation

Tampa Electric currently uses two criteria to measure the reliability of its generating system. The company utilizes a 20% reserve margin criteria and a 7% minimum summer supply side reserve margin criteria. Tampa Electric's approach to calculating percent reserves are consistent with that outlined in the settlement agreement. The calculation of the minimum 20% reserve margin employs an industry accepted method of using total available generating and firm purchased power capacity (capacity less planned maintenance and contracted unit sales) and subtracting the annual firm peak load, then dividing by the firm peak load, and multiplying by 100%. Since the reserve margin calculation assumes no forced outages, Tampa Electric includes the purchased power contract with Invenergy for the Hardee Power Station in its available capacity. Contractually, Hardee Power Station is planned to be available to Tampa Electric at the time of system peak. Also, the capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from Tampa Electric's available capacity.

Tampa Electric's summer supply-side reserve margin is calculated by dividing the difference of projected supply-side resources and projected total peak demand by the forecasted firm peak demand. The total peak demand includes the summer firm peak demand, and interruptible and load management loads.

Transmission

The following criteria are used as guidelines for proposing system expansion and/or improvement projects. A detailed engineering study must be performed prior to making a prudent decision to initiate a project.

Tampa Electric follows FRCC planning criteria as contained in its Principles and Guides for Planning Reliable Bulk Electric Systems. The FRCC planning guide is based on NERC Planning Reliability Standards, which are used to measure system adequacy. In general the NERC standards state that the transmission system will remain stable, within the applicable thermal and voltage rating limits, without cascading outages, under normal, single and multiple contingency conditions.

Generation Dispatch Modeled

The generation dispatched in the planning models is dictated on an economic basis and is calculated by the Economic Dispatch (ECDI) function of the PSS/E loadflow software. The ECDI function schedules the unit dispatch so that the total generation cost required to meet the projected load is minimized. This is the generation scenario contained in the power flow cases submitted to fulfill the requirements of FERC Form 715 and the FRCC.

Since varying load levels and unplanned and planned unit outages can result in a system dispatch that varies significantly from a base plan, bulk transmission planners also investigate several scenarios that may stress Tampa Electric's transmission system. These additional generation sensitivities are analyzed to ensure the integrity of the bulk transmission system under maximized bulk power flows.

Transmission System Planning Loading Limits Criteria

Tampa Electric follows the FRCC planning criteria as contained in of the FRCC Standards Handbook and NERC Standards. In addition to FRCC criteria, Tampa Electric utilizes company-specific planning criteria. The following table summarizes the thresholds, which alert planners to problematic transmission lines and transformers.

Transmission System Loading Units

TRANSMISSION SYSTEMS CONDITIONS	MAXIMUM ACCEPTABLE LOADING UNIT FOR TRANSFORMERS AND TRANSMISSION LINES
All elements in service	100%
Single Contingency (pre-switching)	115%
Single Contingency (post-switching)	100%
Bus Outages (pre-switching)	115%
Bus Outages (post-switching)	100%

The transmission system is planned to allow voltage control on the 13.2 kV distribution buses between 1.023 and 1.043 per unit. For screening purposes, this criterion can be approximated by the following transmission system voltage limits.

Transmission System Voltage Units

TRANSMISSION SYSTEMS CONDITIONS	INDUSTRIAL SUBSTATION BUSES AT POINT-OF-SERVICE	69 KV BUSES	138KV AND 230 KV BUSES
Single Contingency (pre-switching)	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.
Single Contingency (post-switching)	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.
Bus Outages	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.

Available Transmission Transfer Capability (ATC) Criteria

Tampa Electric Company complies with the FRCC ATC calculation methodology as well as the principles contained in the NERC Standards relating to ATC.

Transmission Planning Assessment Practices

Base Case Operating Conditions

The System Planning department ensures that the Tampa Electric Company transmission system can support peak and off-peak system load levels without violation of the loading and voltage criteria stated in the Generation and Transmission Reliability Criteria section of this document.

Single Contingency Planning Criteria

The Tampa Electric Company transmission system is designed such that any single branch (transmission line or autotransformer) can be removed from service up to the forecasted peak load level without any violations of the criteria stated in the Generation and Transmission Reliability Criteria section of this document.

Multiple Contingency Planning Criteria

Double contingencies involving two branches out of service simultaneously are analyzed at 100% of peak load level. The Tampa Electric Company transmission system is designed such that these double contingencies do not cause violation of NERC criteria.

Transmission Construction and Upgrade Plans

A detailed list of the construction projects can be found in Chapter IV, Schedule 10. This list represents the latest transmission expansion plan available. However, due to the timing of this document in relationship to the company's internal planning schedule, this plan may change in the near future.

Supply Side Resources Procurement Process

Tampa Electric will manage the procurement process in accordance with established policies and procedures. Prospective suppliers of supply side resources as well as suppliers of equipment and services will be identified using various data base resources and competitive bid evaluations, and will be used in developing award recommendations to management.

This process will allow for future supply side resources to be supplied from self-build, purchase power, or competitively bid third parties. Consistent with company practice, bidders will be encouraged to propose incentive arrangements that promote development and implementation of cost savings and process improvement recommendations.

DSM Energy Savings Durability

Tampa Electric verifies the durability of energy savings from its conservation and load management programs by several methods. First, Tampa Electric has established a monitoring and evaluation process where historical analysis validates the energy savings. These include:

(**1**) periodic system load reduction analyses for residential load management (Prime Time) to confirm the accuracy of Tampa Electric's load reduction estimation formulas;

(**2**) billing analysis of various program participants compared to control groups to minimize the impact of weather abnormalities;

(**3**) periodic DOE2 modeling of various program participants to evaluate savings achieved in residential programs involving building components;

(**4**) end-use sampling of building segments to validate savings achieved in Conservation Value and Commercial Indoor Lighting programs; and

(**5**) in commercial programs such as Standby Generator and Commercial Load Management, the reductions are verified through metering of loads under control to determine the demand and energy savings.

Second, the programs are designed to promote the use of high-efficiency equipment having permanent installation characteristics. Specifically, those programs that promote the installation of energy efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, air distribution system repairs, DX commercial cooling units) have program standards that require the new equipment to be installed in a permanent manner thus insuring their durability.

Tampa Electric's Renewable Energy Programs

Tampa Electric has offered a pilot Renewable Energy Program for several years. Due to the recent success of the pilot, permanent program status was requested by the company and approved by the Commission in Order No. PSC-07-0052-CO-EG, Docket No. 06078-EG, issued January 19, 2007.

Through December 2006, Tampa Electric's Renewable Energy Program has approximately 1,500 customers purchasing over 2,000 blocks of renewable energy each month. Participation for 2006 alone increased the total number of participants in the program by over 52 percent since inception. In addition, with the permanent program status effective January 2007, the company doubled the renewable energy block size from 100 to 200 kWh per month.

Tampa Electric is one of the few electric utilities in the state that uses renewable generation produced in the State of Florida. The company's renewable generation portfolio consists of four photovoltaic (PV) arrays totaling 40 kW. The PV arrays are installed at the Museum of Science and Industry, Walker Middle and Middleton High schools and Tampa Electric's Manatee Viewing Center. Additionally, Tampa Electric is evaluating a methodology to utilize captured methane gas emanating from a Hillsborough County landfill.

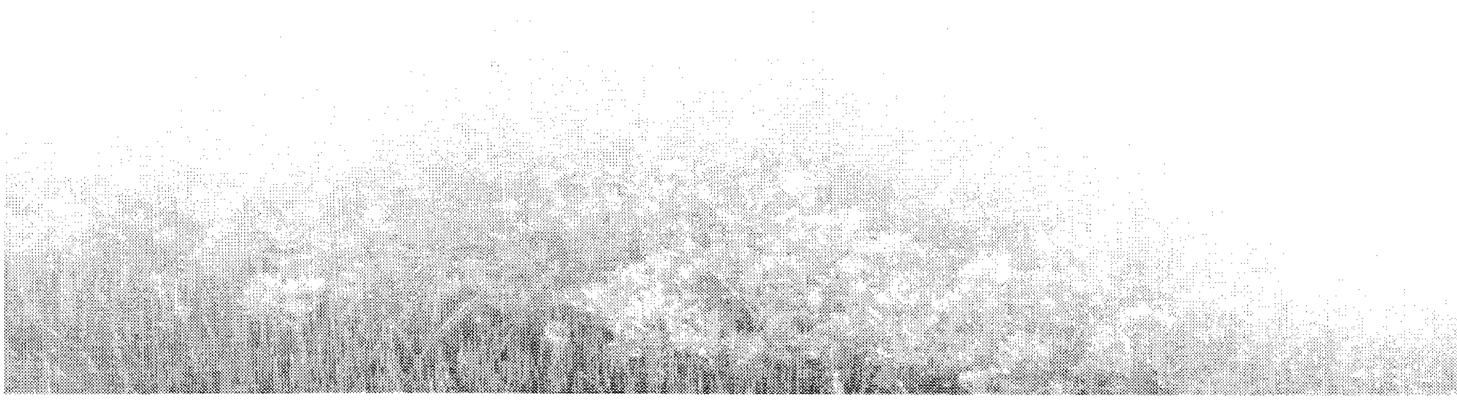
Program growth has now reached a point where it has become necessary to supplement the company's renewable resources with incremental purchases from a biomass facility in south Florida. Through December 2006, participating customers have utilized over 4.5 GWH of renewable energy since the program inception.

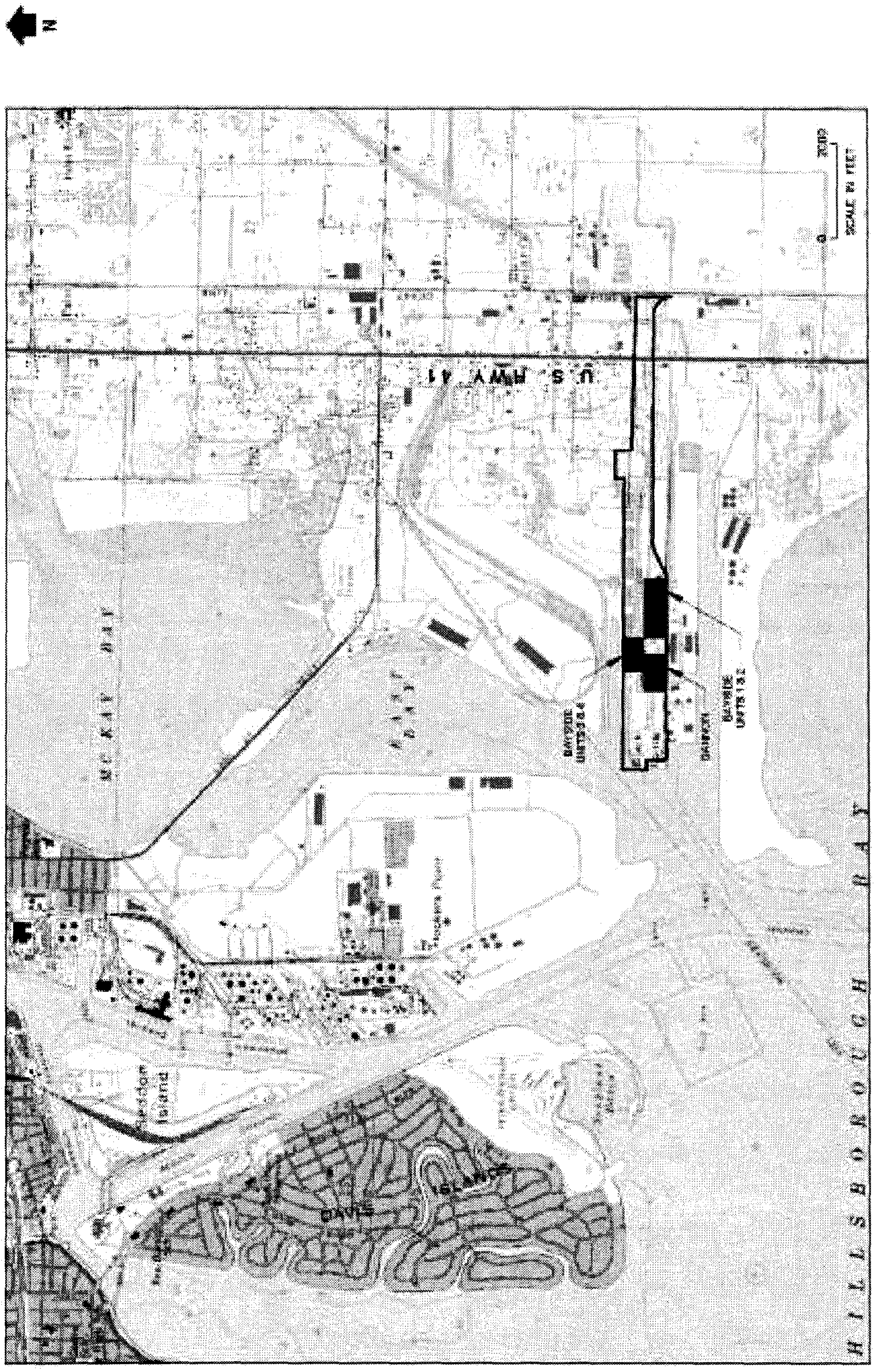
Tampa Electric recognizes the need and value of renewable generation for the future, and to that end, the company continues to investigate and obtain the most cost-effective methods of system generation and available off-system incremental purchases.

chapter 6

Environmental and Land Use Information

The future generating capacity additions identified in Chapter IV could occur at H.L. Culbreath Bayside Power station, Polk Power Station, or Big Bend Power Station. The H.L. Culbreath Bayside Power Station site is located in Hillsborough County on Port Sutton Road (See Figure VI-1), Polk Power station site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-2) and Big Bend Power Station is located in Hillsborough County on Big Bend Road (See Figure VI-3). All facilities are currently permitted as existing power plant sites. Additional land use requirements and/or alternative site locations are not currently under consideration.





F.J. GANNON / BAYSIDE LOCATION MAP
SOURCE: USGS QUAD, TAMPA, FL 1981

Figure VI-2

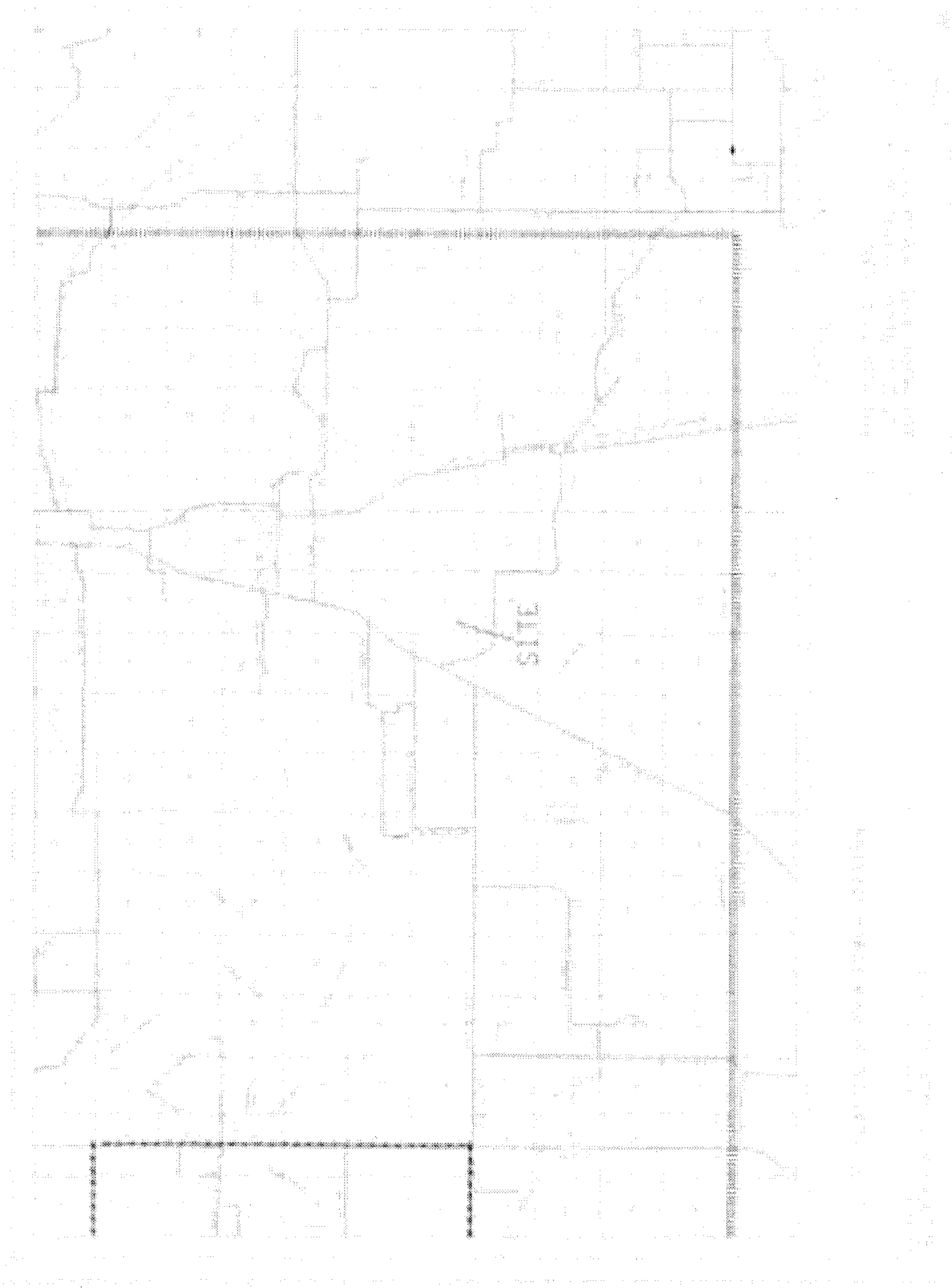
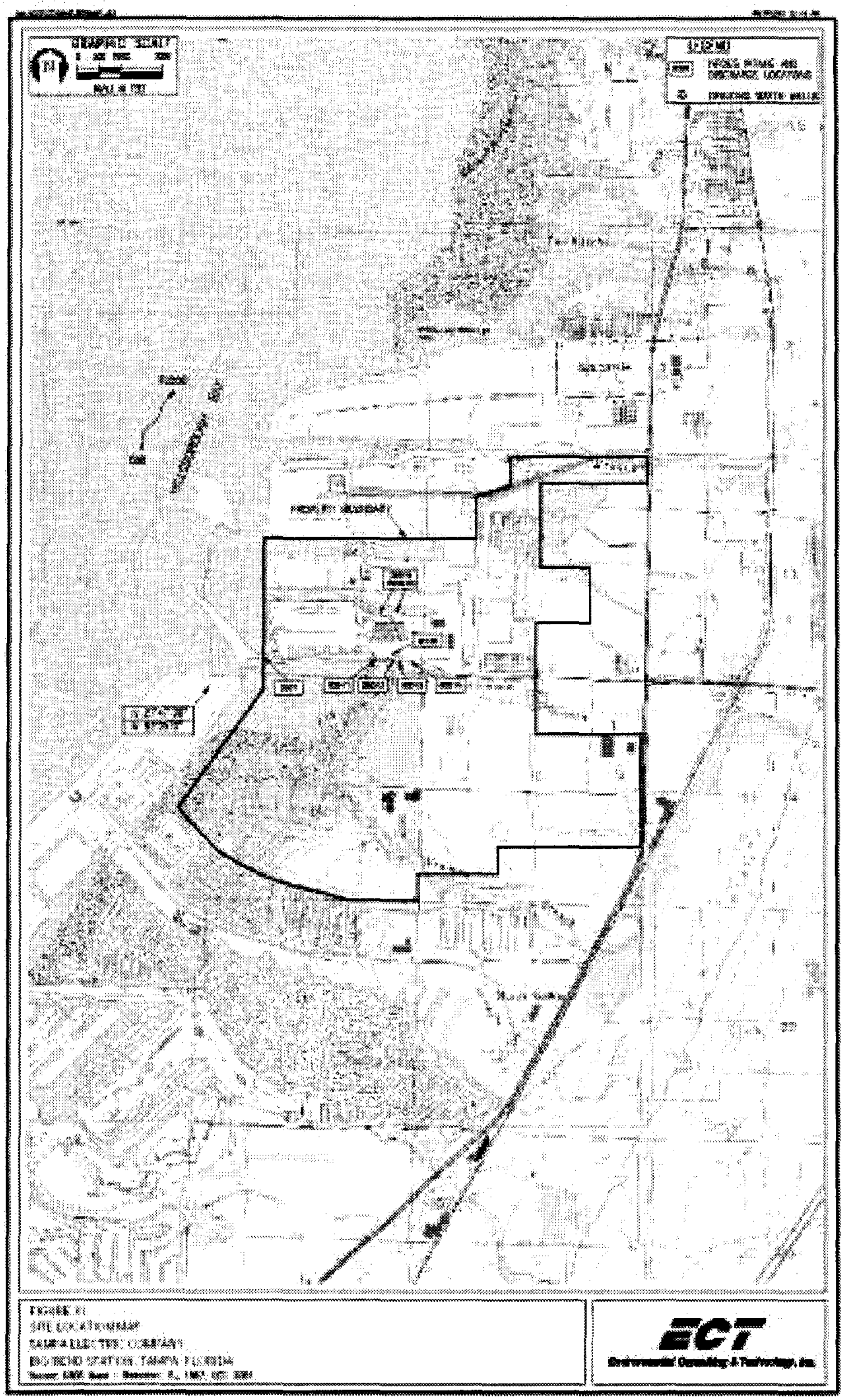


Figure VI-3


PROPERTY BOUNDARY
SITE LOCATION MAP
TAMPA ELECTRIC COMPANY
BIG BEND STATION, TAMPA, FLORIDA
ECT

DIRECT TESTIMONY OF
WILLIAM M. JASPER
ON BEHALF OF APPALACHIAN POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA
IN CASE NO. 06-0033-E-CN

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William M. Jasper. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Director – New Generation Projects for American Electric Power Service Corporation ("AEPSC"), a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Appalachian Power Company ("APCo" or the "Company").

I am responsible for the development and implementation of new generation projects for AEP. In this regard, I also provide data to be used in analyses performed by AEP personnel. Once the need for new generation has been established, and the appropriate technology has been selected, my job is to find the optimal solution for implementing the project, which employs that technology to satisfy that need. I am then responsible for executing that solution by overseeing the design, procurement, construction and startup of the new generation facility. In my position, I am responsible for those aspects of APCo's proposed Integrated Gasification Combined Cycle ("IGCC") facility.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND RELEVANT BUSINESS EXPERIENCE?

A. I have a Bachelors of Science degree in Mechanical Engineering from the University of Houston. I have attended many seminars and programs related to my work. These include the Public Utility Executive Program at the University of Michigan and the Program for Management Development at Harvard University.

I began my career in 1972 with Central Power and Light Company ("CPL"), a subsidiary of Central and South West Corporation ("CSW"). I held several positions relating to the startup and operations of power generation facilities including Results Engineer, Assistant Plant Manager, Operations Supervisor and Plant Manager. I then was promoted to Director of Environmental Services where I was responsible for the environmental compliance and permitting programs. In 1991, I became Director of Engineering Services. I was responsible for the planning and operation of CPL's bulk power system. This included transmission and generation planning and generation and transmission dispatching. Later, my responsibilities were expanded to include transmission and substation engineering and construction, as well as CPL's transformer and meter shops.

In 1994, I transferred to CSW Energy, an affiliate company, as Director of Engineering and Construction. My responsibilities covered the technical support for development of independent power projects developed by CSW Energy. Once these projects were developed, I was responsible for the execution of the projects. In that role, I oversaw the conceptual design of the facility, established the contracting strategies, negotiated the contracts for the engineering, procurement and construction of those facilities, and reviewed the turnover and acceptance of the facilities from the contractors.

With the merger of CSW and AEP in 2000, I was named Director of Major Projects. In that role, I was responsible for the execution of major generation projects in AEP's western fleet. In 2004, I was named to the position of Director – Field Services, responsible for major capital projects in AEP's entire existing fleet. Later in 2004, I accepted the position of Director – New Generation Projects, responsible for IGCC, natural gas combined cycle and natural gas peaking projects. In 2007 my position was expanded to give me responsibility for all new generation projects.

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide an overview of the process APCo has followed regarding its proposal to construct an IGCC facility adjacent to its Mountaineer power plant located in New Haven, West Virginia. In doing so, I will provide an overview of the feasibility study and the Front End Engineering and Design ("FEED") that General Electric Company, through its GE Energy Business, and Bechtel Power Corporation ("GE/Bechtel") performed in conjunction with AEP. I will then discuss the cost estimates developed as a result of the FEED and report on the status of contract negotiations with GE/Bechtel. Finally, I will summarize the current schedule and path forward for APCo's IGCC project.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. In addition to my testimony, I am sponsoring WMJ Exhibit Nos. 2 and 3.

Q. PLEASE SUMMARIZE THE PROCESS THAT HAS LED APCO TO PROPOSE THE CONSTRUCTION OF A 629 MW IGCC GENERATING FACILITY ADJACENT TO ITS MOUNTAINEER POWER PLANT.

A. Once an IGCC facility was identified as a viable option for the next generation of coal-fired power plants on the AEP East System, AEP commissioned a feasibility study to evaluate the feasibility, scope and cost of an AEP-specific IGCC plant. Based upon the results of the feasibility study, AEP initiated FEED for an IGCC plant in both Ohio and West Virginia. In parallel with FEED, we have negotiated the substantive terms of an Engineering, Procurement and Construction ("EPC") Contract with GE/Bechtel, which, to focus on the West Virginia project, will permit construction of an IGCC plant adjacent to the Mountaineer plant to begin once APCo has obtained all necessary regulatory approvals.

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Q. WHAT OBJECTIVES DID AEP AND THE COMPANY PURSUE THROUGHOUT THIS PROCESS?

A. From the onset, the objective has been to enter into a lump-sum turnkey EPC Contract with an entity to provide for coverage of substantially all of the scope of the IGCC project within one commercial package. Under this approach, one supplier will be responsible for the design, supply, construction, startup, testing and warranties of all major equipment and supporting systems. This will allow substantially all of the facility to be covered by one set of guarantees. These

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guarantees will have much higher limits, and be more comprehensive than would be the case if equipment and systems were supplied on an individual vendor basis.

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This approach can be contrasted with the execution model that has been used by others for similar projects. In that model, a potential owner of an IGCC facility would purchase a license from a gasification supplier. That owner would then contract with someone to build the equipment in accordance with the design information supplied with the license purchased from the technology supplier. It would then contract with another party to incorporate this into the design of the overall facility. The owner would also purchase all of the other equipment, such as gas turbines, to be incorporated into this facility design. The owner would contract with yet another third-party to construct the facility. The owner or some other party would then be responsible for starting-up the facility. The overall outcome of this approach is that there is no one party, other than the owner, who has the responsibility for assuring that the end product functions as expected. In AEP/APCo's judgment, the risk associated with this model is inadvisable, both for themselves and for APCo's customers.

Q. WHY WAS GE/BECHTEL SELECTED TO WORK ON THE IGCC PROJECT?

A. At the inception of the feasibility study, GE/Bechtel was identified as the obvious team capable of supplying a utility-grade IGCC facility with a commercial package consistent with AEP's execution model. GE has a long history of providing equipment and services to the utility industry. In 2004, GE acquired the gasification business previously owned by ChevronTexaco and subsequently

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integrated this business into the overall GE Energy family of businesses. Bechtel has a similarly long history in executing global power, refining and chemical process projects. At this stage of the process, GE/Bechtel continues to be the logical choice to act as the single EPC contractor for APCo's IGCC project.

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Feasibility Study

Q. PLEASE DESCRIBE THE PROCESS THAT WAS INITIALLY UTILIZED TO DETERMINE THE FEASIBILITY, SCOPE AND THE COST OF A NEW IGCC PLANT.

A. In the early part of 2005, AEPSC requested that GE/Bechtel conduct a feasibility study for an AEP-specific IGCC plant. GE/Bechtel conducted the feasibility study in parallel with their efforts to develop the scope and cost of a standard GE/Bechtel "reference" plant.

Q. WHAT DOES THE TERM "REFERENCE" PLANT MEAN?

A. The term "reference" plant describes a standard plant design that can be used as the starting point for the design of a specific plant. This standard design sets the definition of most of the major equipment of the plant. With an "off the shelf" estimate of a reference plant available, it is easier to develop a scope and cost estimate for the reference plant and determine the incremental cost of AEP-specific options contemplated as additions or deletions from the scope and estimate of the reference plant.

Q. HOW CLOSELY WILL THE RESULTING PLANT MIRROR THE REFERENCE PLANT?

A. The joint efforts of AEP and GE/Bechtel have produced a number of optimizations, as further described below, that constitute a prudent balance of operating flexibility, capital cost, O&M costs and efficiency necessary and desirable in such a facility operating in a utility environment. In most material respects, the AEP plant will conform to the GE/Bechtel reference plant design, but certain design modifications have been made, such as expanding the fuel envelope to enable using a wide range of Appalachian coals.

Q. WHY IS CONSISTENCY WITH THE REFERENCE PLANT DESIGN IMPORTANT?

A. A great deal of work has gone into the development of the reference plant. Significant synergy and efficiency is gained by capitalizing on the engineering, procurement and construction planning developed for the reference plant case. Also, lessons learned from similar facilities designed and built according to the reference plant design will be more directly transferable among plants, including the APCo facility, if the designs are comparable. This will facilitate ongoing enhancements in reliability, availability and efficiency.

Q. WHAT WERE THE RESULTS OF THE FEASIBILITY STUDY?

A. It demonstrated the feasibility of building an IGCC plant and provided a basic definition of the configuration of the proposed plant. During the development of this basic scope definition, there were a number of analyses performed to consider the internal processes of the plant to allow the determination of those processes that would best balance the costs of, and the benefits derived from, exercising a certain design-related option. Additionally, the feasibility study provided for the development of a "high level" project schedule and a generic cost estimate.

Q. DID THE FEASIBILITY STUDY CONDUCTED BY GE/BECHTEL COVER THE ENTIRE SCOPE OF THE PROPOSED PLANT?

A. No. AEP developed the scope for certain parts of the plant. The portions of scope developed by AEP include those site-related items, or plant systems, with which we are most familiar. These included site development, fuel and material unloading and handling, switchyard and transmission interconnection, river frontage improvements and development, and permitting. Permitting is described in more detail by Company witness Mallan.

Q. HOW DID AEP DEVELOP ITS PORTIONS OF THE SCOPE?

A. Discrete points of interface between GE/Bechtel and AEP were identified (e.g. potable water line, natural gas line, coal transfer, slag conveyor). For that portion of scope undertaken by AEP, we further defined those items and developed cost estimates based on a combination of internal experience and indicative cost estimates from manufacturers and vendors obtained in parallel with the feasibility study.

Q. WHAT STEPS FOLLOWED THE FEASIBILITY STUDY?

A. AEP evaluated a number of options regarding the configuration of the IGCC plant to optimize the costs and benefits of those options. These options included the installation of spare equipment for enhanced reliability, whether or not to include a spare gasifier in the scope, the technology to be employed for acid gas removal, and a variety of potential performance enhancements.

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With the conceptual scope of the plant considered finalized for the purposes of the feasibility study, the project could then move to the next phase, which is the FEED.

FEED Phase

Q. WHAT HAPPENED DURING THE FEED PHASE?

A. During that phase, GE/Bechtel performed more detailed engineering and design of the AEP-specific plant. This included defining and selecting specific equipment to be utilized in the plant. This allowed GE/Bechtel to obtain vendor pricing on this equipment and to develop the quantities of bulk commodities such as piping, cable and conduit, concrete and steel for the ultimate installation. All of this led to the development of a November, 2006 cost estimate and a definitive schedule for the AEP-specific plant.

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Q. HOW WAS AEP INVOLVED WITH THE ENGINEERING AND DESIGN OF THE PROPOSED FACILITY DURING FEED?

A. AEP took a hands-on approach with the development of the proposed facility. A number of seasoned AEP employees with utility, IGCC, and process industry experience were assembled and integrated into the GE/Bechtel project team. These AEP personnel had many years of operational and process safety knowledge, knowledge of IGCC lessons learned, and utility operations experience that could be relied upon to properly configure and integrate an IGCC facility into AEP East/APCo's generating fleet. The combined technological knowledge of the integrated team proved highly effective, as the following example illustrates.

The meaning of the term baseload generation is largely region specific. In the AEP East system, low-cost “baseload” coal units must be able to turn down during periods of low load. These facilities often operate at 100% of their capacity for the majority of the day, and turn down to low loads during off-peak hours. Important design features to allow this capability are necessary in a commercial-scale AEP East/APCo IGCC facility. Through the AEP team members communicating such needs throughout the design process, the end product will be a facility that matches these needs, as it will be able to operate reliably at loads lower than 100%.

Q. WHAT WAS THE WORK PRODUCT THAT WAS DEVELOPED IN FEED?

A. The primary products of FEED were a definitive scope of work, a more detailed set of plant design specifications to enable the procurement of major equipment, fuel envelope, plant performance data, emissions data, schedule, and a cost estimate (November 2006) for the completion of the project. A summary of the FEED work product is contained in WMJ Exhibit No. 2.

Q. PLEASE DESCRIBE THE WORK THAT LED TO THE DEVELOPMENT OF THE DEFINITIVE SCOPE OF WORK.

A. The scope of work was split between GE/Bechtel and AEP into areas of greatest expertise. The GE/Bechtel scope consists of all equipment and activities within the boundary limits of the IGCC facility, such as air separation, gasification, gas cleanup, and power block. The AEP scope consists of ancillary equipment and activities surrounding the facility, such as site preparation, materials handling (barge unloading, coal yard, slag disposal), landfill development, natural gas supply line, and river development. AEP also assumed the scope related to the transmission interconnection.

Q. PLEASE DESCRIBE THE WORK THAT LED TO THE DEVELOPMENT OF THE PLANT DESIGN SPECIFICATIONS AND ULTIMATELY, THE COST DEVELOPMENT.

A. First, a design basis was developed for the various engineering disciplines. This allowed all engineering work to be performed using the same set of design conditions (e.g. ambient temperature range, plant elevation, applicable building codes, functional requirements).

With the design basis set, Process Flow Diagrams ("PFDs") were developed. These PFDs illustrate the basic flow of materials to/from major process systems. They included an elementary level of detail for process control, and serve as the starting point for further development.

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Many deliverable products were derived from the PFDs. Modeling work was performed to create Heat and Material Balances ("HMBs"). These HMBs provide information, such as temperature, pressure, flow, and composition for all of the process streams on the PFDs. In addition, the PFDs were used to develop Process Data Sheets ("PDSs"). These PDSs provide information about the operating and design conditions of individual pieces of process equipment. Finally, the PFDs were also used to create Piping and Instrumentation Diagrams ("P&IDs"). These P&IDs depict greater detail of process piping, instrumentation and control, and equipment.

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The PFDs, PDSs, P&IDs and HMBs were then used to create Material Selection Guides ("MSGs"). The MSGs provide information regarding the materials of construction, size, and wall thickness of process piping and equipment.

The engineering documents described above provided the basis for the sizing and quantities of piping, cable, equipment, and other bulk materials that were used in the estimating process. Costs of materials and equipment were estimated using a combination of GE/Bechtel in-house information, as well as bids obtained from vendors.

Q. WERE ANY OTHER ACTIVITIES UNDERTAKEN DURING FEED?

A. Yes. In addition to the engineering workflow described above, many design considerations and optimizations were performed concurrently.

Q. WHAT WERE SOME OF THE MAIN DESIGN CONSIDERATIONS AND OPTIMIZATIONS THAT WERE PERFORMED?

A. One main design consideration was related to the fuel to be used in the gasification process. Simply specifying eastern bituminous coal as a fuel source was not adequate from a design perspective, given the variability in key coal constituents such as ash, sulfur and chlorides. The facility should be able to handle a very wide range of these constituents to enable the Company to take advantage of fluctuations in coal availability and cost. Moreover, the facility should have the flexibility to use various specifications of coal that are being produced from time to time in the general location of the facility. Of course, some constraints on fuel flexibility are unavoidable. Practical design considerations around sizing of slag lines (ash dependant), sizing of the Acid Gas Removal and Sulfur Removal Units (sulfur dependant), grade of steel metallurgy (chloride dependant), and the sizing of the Air Separation Unit (overall fuel characteristics), impose certain limitations. Through cooperative work by the AEPSC Fuel, Emissions, and Logistics Group and GE/Bechtel, a fuel envelope was defined to allow the facility to achieve fuel flexibility, without adding undue capital costs to the project.

Numerous design optimizations took place around the Acid Gas Removal System (AGR). The AGR uses a solvent to remove sulfur compounds from the syngas. Many variables must be optimized in an AGR design, including: level of removal, solvent temperature, solvent flow, initial capital costs, operating and maintenance costs and effects on plant output and efficiency. These variables were analyzed by AEP, GE/Bechtel, and UOP, who is the technology licensor of the Selexol solvent used for sulfur removal.

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Q. PLEASE DESCRIBE THE PJM INTERCONNECTION STUDY PROCESS.

A. The process for obtaining the Interconnection Services Agreement with PJM began in January 2005. It is a three-study process that determines the feasibility of different interconnection plans, the impact on the existing transmission network, and the facilities cost to implement the agreed upon plan.

The first study, completed by PJM in August 2005, was the PJM Feasibility Study that presented viable plans for connecting either a one or two unit IGCC generating facility at the Mountaineer site into the existing 765kV, 345kV and 138kV systems. The next study was the System Impact Study, which was completed in February 2006. This study determined the estimated direct connection costs and the network impacts and associated estimated costs for connection of one or two units at the Mountaineer location. The third and final study is the PJM Facilities Study. PJM in consultation with AEP Transmission is nearing completion of the PJM Facilities Study. The PJM Facilities Study is a more refined detail analysis that will assess the impact of the new generation to be connected to the transmission grid and identify the necessary interconnection methods, the network upgrades, and the more definitive associated costs.

Upon receipt of the PJM Facilities Study, PJM will forward a draft Interconnection Services Agreement that will undergo a review and negotiation process prior to the final execution. The entire PJM study process has consistently indicated that the transmission grid at the Mountaineer site is well suited for the power transfer capability necessary for the total generation output.

Q. YOU MENTIONED EARLIER GE/BECHTEL'S ABILITY TO OFFER A COMMERCIAL PACKAGE WHICH COVERS THE FACILITY WITH ONE SET OF GUARANTEES. PLEASE DESCRIBE THE KEY PROVISIONS OF THESE GUARANTEES.

A. At the highest level, it is critical that the facility be capable of operating in accordance with all permits and applicable laws. As APCo is making a significant investment in this facility it is also important to be assured that it will get what it pays for, in terms of performance, operating flexibility and timely completion. This will be assured by guarantees related to things such as emissions, output, heat rate, turndown and ramp rate.

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EPC Contract and Cost Estimate

Q. HOW WILL THE ENGINEERING, PROCUREMENT AND CONSTRUCTION CONTRACT ("EPC CONTRACT") WITH GE/BECHTEL BE STRUCTURED?

A. GE/Bechtel will act as a single contractor, having essentially joint and several liability for performance of the EPC Contract. It is anticipated that the EPC Contract, of which the major terms have been agreed to by the parties, will be executed later this year. The EPC Contract will be structured so as to accommodate the uncertainty as to when APCo will be able to give GE/Bechtel a full, complete release to proceed with the work, also referred to as Notice To Proceed ("NTP"). APCo will not give GE/Bechtel this NTP until appropriate regulatory approvals have been obtained.

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Q. WHAT IS THE ESTIMATED COST OF THE PROPOSED FACILITY?

A. The estimated direct cost of the base plant (baseline cost estimate) with transmission interconnection is $2.16 billion, based on November, 2006 pricing, prior to the addition of Company overheads. It should be understood that this is an estimate.

The market has been extremely volatile in recent years, making it impossible to get reasonable pricing fixed at this time. GE/Bechtel is unable to fix its equipment pricing, material costs and labor rates in advance. This cost estimate is based on the scope defined during FEED, and pricing as of the completion of the bulk of the FEED cost estimate work in November, 2006, and is based on certain pricing assumptions. It is common engineering practice to include in projects a dollar value for unforeseen escalation and contingency. In the case of this project, the Company has built-in approximately $250 million of escalation and contingency. The NTP would be issued by APCo after it receives regulatory approval, but no sooner than seven months after execution of the EPC Contract and issuance of a partial, Limited Notice to Proceed ("LNTP"), under which GE/Bechtel would continue to fine tune the scope and costs and revise its portion of the baseline cost estimate.

Q. PLEASE DESCRIBE THE PROCESS BY WHICH THIS REVISED BASELINE COST ESTIMATE WILL BE UPDATED TO REFLECT CHANGES IN PRICING.

A. GE/Bechtel and APCo have developed an adjustment mechanism to deal with significant market escalations in large plant construction costs, as well as other commodities, that have impacted and are expected to continue to impact large plant. A significant Company concern with respect to the proposed IGCC facility is the rapidly escalating costs for commodities used in large construction projects. Company witness Rencheck discusses in his testimony the rapid escalation of key commodity prices in the EPC industry. In such a situation, no contractor is willing to assume this risk for a multi-year project. Even if a contractor was willing to do so, its estimated price for the project would reflect this risk and the resulting price estimate would be much higher. To deal with volatility, GE/Bechtel will, following the issuance of APCo's NTP, adjust its prices for equipment, materials and labor on various cost categories, to reflect updated pricing values and vendor quotes.

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The various categories of costs that will be subject to updating are:

- Major Equipment and Subcontracts, with a value more than $1 million, will be competitively re-bid at the appropriate time based on the project schedule, and substituted for the pricing obtained from bids for the FEED cost estimate.
- Plant Equipment and Subcontracts, with a value less than $1 million, will also be competitively re-bid at the appropriate time based on the project schedule, and substituted for the pricing obtained from bids, or from historical data from the FEED cost estimate.
- Bulk Materials. At the time of actual purchase of bulk materials, actual pricing will be obtained through competitive quotes and used to adjust the unit prices for bulk materials.
- Construction Equipment and Construction and Start-up Materials. At the time of actual purchase of equipment and construction and start-up materials, actual pricing will be obtained through competitive bidding. Gasoline and diesel prices will be adjusted based on prices published by the Department of Energy.
- Craft Labor. Actual corresponding labor rates will be used to recalculate the labor expenses actually incurred on a monthly basis.
- Non-Manual Service Rates. Actual corresponding rates paid for these support staff personnel during the execution of the project will be used to recalculate the costs on an annual basis.

- GE Manufactured and Proprietary Equipment. The mechanism for adjusting the price of GE manufactured and proprietary equipment will be agreed upon prior to executing the EPC Contract.

Q. WHAT METHOD WAS USED TO ESTIMATE WHEN THE DIRECT COSTS WOULD BE INCURRED DURING THE PERIOD OF CONSTRUCTION?

A. Based on my experience with generating plant and other utility-related construction, I estimated the monthly expenditures taking into consideration: 1) GE/Bechtel's payment schedules for the GE/Bechtel scope of work, and 2) the shape of other EPC cash flow curves related to other projects for the AEP scope of work. These monthly direct costs shown in WMJ Exhibit No. 3 were then provided to Company witness Eads for his use.

Schedule

Q. PLEASE PROVIDE AN OVERVIEW OF THE NEXT STEPS IN THIS PROJECT.

A. Outstanding EPC Contract details will be finalized, and ongoing process optimizations will take place. These optimizations include the evaluation of an alternative wastewater treatment design, which would discharge treated wastewater into an underground disposal well, rather than the Ohio River. After EPC contract details have been finalized, the EPC Contract will be executed, and a limited notice to proceed will be given to GE/Bechtel. Upon receipt of the necessary regulatory approvals, APCo will then be in a position to provide GE/Bechtel with an NTP.

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Q. PLEASE PROVIDE A MAJOR MILESTONE PROJECT SCHEDULE FOR THE EPC PHASE OF THE PROJECT.

A. The major milestone schedule is provided as Appendix I in WMJ Exhibit No. 2 The schedule shows target substantial completion date 46 months after full notice to proceed is given to the Contractor.

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Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Privileged or Confidential Information Redacted

DOE F 4600.1# (4/05)

U.S. DEPARTMENT OF ENERGY

NOT; : OF FINANCIAL ASSISTANCE A; RD

Under the authority of Public Law 95-91 DOE Organization Act, as amended by PL 102-486 Energy Policy Act

1. PROJECT TITLE MESABA ENERGY PROJECT – UNIT 1

2. INSTRUMENT TYPE
☐ GRANT ☒ COOPERATIVE AGREEMENT

3. R PIENT (Name, address, zip code)
MEP-I LLC
11100 Wayzata Boulevard, Suite 305
Minnetonka, Minnesota 55305

4. INSTRUMENT NO. DE-FC26-06NT42385

5. AMENDMENT NO. A000

6. BUDGET PERIOD FROM: 6/1/06 THRU: 4/28/08

7. PROJECT PERIOD FROM: 6/1/06 THRU: 2/28/13

8. RECIPIENT PROJECT DIRECTOR (Name, phone and E-mail)
Jim Milkovich jimmilkovich@excelsiorenergy.com
952/847-2371 FAX: 2373

9. RECIPIENT BUSINESS OFFICER (Name, phone and E-mail)
Renee J. Sass reneesass@excelsiorenergy.com
952/847-2363 FAX: 2373

10. TYPE OF AWARD
☒ NEW ☐ CONTINUATION ☐ RENEWAL
☐ REVISION ☐ INCREMENTAL FUNDING

11. DOE PROJECT OFFICER (Name, address, phone and E-mail)
National Energy Technology Laboratory
ATTN: Jason T. Lewis jason.lewis@netl.doe.gov
3610 Collins Ferry Road, P. O. Box 880
Morgantown, WV 26507-0880
304/285-4724 FAX: 4403 or 4469

12. ADMINISTERED FOR DOE BY (Name, address, phone and E-mail)
National Energy Technology Laboratory
ATTN: William R. Mundorf william.mundorf@netl.doe.gov
626 Cochrans Mill Road, P. O. Box 10940
Pittsburgh, PA 15236-0940
412/386-4483 FAX: 6137

13. RECIPIENT TYPE
☐ STATE GOV'T ☐ INDIAN TRIBAL GOV'T ☐ HOSPITAL ☒ FOR PROFIT ORGANIZATION ☐ INDIVIDUAL
☐ LOCAL GOV'T ☐ INSTITUTION OF HIGHER EDUCATION ☐ OTHER NONPROFIT ORGANIZATION ☒ C ☐ P ☐ SP ☐ OTHER (Specify) ______

14. ACCOUNTING AND APPROPRIATIONS DATA:
150 2005 31 220322 61000000 25500 1610353

15. EMPLOYER I.D. NUMBER
a. TIN: 41-2019511
b. DUNS: 14-626-2915

16. BUDGET AND FUNDING INFORMATION

a. CURRENT BUDGET PERIOD INFORMATION		b. CUMULATIVE DOE OBLIGATIONS	
(1) DOE Funds Obligated This Action	$	(1) This Budget Period [Total of lines a.(1) and a.(3)]	$
(2) DOE Funds Authorized for Carry Over	$		
(3) DOE Funds Previously Obligated in this Budget Period	$	(2) Prior Budget Periods	$
(4) DOE Share of Total Approved Budget	$		
(5) Recipient Share of Total Approved Budget	$	(3) Project Period to Date [Total of lines b.(1) and b.(2)]	$
(6) Total Approved Budget	$		

17. TOTAL ESTIMATED COST OF PROJECT, INCLUDING DOE FUNDS TO FFRDC: $ 2,155,680,783
(This is the current estimated cost of the project. It is not a promise to award nor an authorization to expend funds in this amount.)

18. AWARD AGREEMENT TERMS AND CONDITIONS
This award/agreement consists of this form plus the following:
a. Special terms and conditions.
b. Applicable program regulations *(specify)* ______ *(Date)* ______
c. DOE Assistance Regulations, 10 CFR Part 600at http://ecfr.gpoaccess.gov or, if the award is a grant to a Federal Demonstration Partnership (FDP) institution, the FDP Terms & Conditions and the DOE FDP Agency Specific Requirements at http://www.nsf.gov/awards/managing/fed_dem_part.jsp.
d. Application/proposal dated 6/14/04 with changes as agreed to by DOE and the Recipient.
e. National Policy Assurances to Be Incorporated as Award Terms at http://grants.pr.doe.gov.

19. REMARKS
This cooperative agreement is subject to the general terms and conditions contained herein.

20. EVIDENCE OF RECIPIENT ACCEPTANCE
Julie Jorgensen May 23 2006
(Signature of Authorized Recipient Official) (Date)
Julie Jorgensen
(Name)
Co-President and CEO
(Title)

21. AWARDED BY
Raymond D. Johnson 5/19/06
(Signature) (Date)
Raymond D. Johnson
(Name)
Contracting Officer
(Title)

DOE Notice of Financial Award and Agreement – dated May 23, 2006 (no link yet)

StarTribune.com | MINNEAPOLIS - ST. PAUL, MINNESOTA

PUC cools to idea of 'clean coal' plant on Iron Range

Commissioners sounded pessimistic on the proposed Iron Range facility but didn't ax it.

By H.J. Cummins, Star Tribune

Last update: November 1, 2007 - 9:57 PM

Minnesota regulators Thursday came close to scrapping a plan to compel the state's energy companies to buy from a proposed $2 billion "clean coal" plant.

Citing growing disillusionment with coal, and assurances from several utilities that they have their energy needs covered, the Minnesota Public Utilities Commission nearly rescinded its Aug. 30 directive to the state's utility companies: that they try to buy from the proposed coal gasification plant when they go shopping for new power sources for the next 10 to 20 years.

The commission stopped short -- for now -- but only after a series of pessimistic prognoses for the Excelsior Energy plant proposed for Minnesota's Iron Range.

"We have a whole paradigm shift now," said commission Chairman Leroy Koppendrayer, pointing to news accounts that coal gasification plants have been delayed or canceled in Colorado, Florida and Arizona.

"We don't ever want to foreclose on the future," Commissioner Phyllis Reha said, "but I think we're all in agreement that what we have in front of us isn't going to fly."

It was the latest setback in a two-year process for Excelsior, including an administrative law judges' advisory ruling in April that the project is "not in the public interest."

Still, Excelsior is not without some victories. It received a $36 million clean-energy grant last spring, and it heard last month that it's on a short list for possible loan guarantees from the U.S. Department of Energy.

Coal and carbon dioxide

The 600-megawatt Excelsior plant would produce electricity through a new process called coal gasification. Unlike traditional coal-burning plants, it has the potential to capture carbon dioxide, the most problematic greenhouse gas.

The Excelsior plant, as proposed, will not initially capture that CO_2 because it's expensive and because the plant has no place to store or send it. Developers say that will be a relatively easy retrofit; opponents say that until that happens, it is little better than traditional plants.

Xcel Energy has long maintained that it won't need any energy from Excelsior in 2011, when the plant would open. And on Wednesday, Minnesota Power said it can meet its energy demands with renewable energy sources through 2020.

A chief executive of Excelsior Energy challenged the utilities' projections after the hearing.

"The commission took at face value the utilities' assertion that there will be no need for fossil [fuel] generation," Julie Jorgensen said.

But there will be shortages, Jorgensen said: "Then they will want to switch to natural gas generation, and it's bad policy to consume massive quantities of natural gas to generate power when consumers can't afford to heat their homes as it is."

H.J. Cummins • 612-673-4671

H.J. Cummins • hcummins@startribune.com

Fossil Energy Power Plant Desk Reference

DOE/NETL-2007/1282

Bituminous Coal and Natural Gas to Electricity Summary Sheets

May 2007

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Fossil Energy Power Plant Desk Reference

DOE/NETL-2007/1282

May 2007

NETL Contact:

Julianne M. Klara
Senior Analyst
Office of Systems, Analysis and Planning

National Energy Technology Laboratory
www.netl.doe.gov

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Preface

The goal of Fossil Energy (FE) research, development, and demonstration (RD&D) is to ensure the availability of ultra-clean, abundant, low-cost, domestic electricity to fuel economic prosperity and strengthen energy security. A broad portfolio of technologies is being developed within the Clean Coal Program to accomplish this objective. Ever increasing technological enhancements are in various stages of the research "pipeline," and multiple paths are being pursued to create a portfolio of promising technologies for RD&D and eventual deployment.

To benchmark the progress of Clean Coal RD&D, it is essential to establish a baseline for comparing the performance of today's fossil energy plant technologies: Pulverized Coal (PC) Combustion, Integrated Gasification Combined Cycle (IGCC), and Natural Gas Combined Cycle (NGCC). NETL commissioned an in-depth analysis to estimate the performance and cost of state-of-the-art power plants taking into account the technological progress in recent years as well as dramatic escalation in labor and material costs. This desk reference provides a brief summary of the performance and cost estimates presented in the report titled, "Cost and Performance Baselines for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281." The plants use either bituminous coal or natural gas to generate electricity using technology that is available today or within the next couple of years for a planned start-up in 2010. All cases analyzed in the study were also designed with CO_2 capture, so that the cost and performance penalties could be estimated and benchmarked. This desk reference summarizes the results at the three levels listed below, allowing the user to drill down to the level of detail desired.

Overview

A top-level overview is provided of all three technologies, with and without CO_2 capture.

Technology-Level

The technology-level summaries drill down one level, to compare like-technologies both with and without CO_2 capture:

- IGCC Technology *(GE Energy, ConocoPhillips E-Gas, Shell)*
- PC Combustion Technology *(sub- and super-critical)*
- NGCC Technology

Plant-Level

Plant-level summary sheets drill down an additional level, to describe each case in terms of the technical, economic, and environmental design basis. A plant description is outlined in some detail for each case, including mass and heat balance, efficiency, capital and operating costs, cost-of-electricity (COE), and cost of avoided CO_2 (if capture is included).

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Fossil Energy Power Plant
Desk Reference
Bituminous Coal and Natural Gas to Electricity

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Overview of Bituminous Baseline Study

Objective and Description

The objective of the *Cost and Performance Baseline for Fossil Energy Plants; Volume 1 (Bituminous Coal and Natural Gas to Electricity)* is to determine cost and performance estimates of the near-term commercial offerings for power plants, both with and without current technology for carbon capture and sequestration (CCS). The study uses consistent design requirements for all technologies examined, as well as up-to-date performance and capital cost estimates. The study timeframe focuses on plants built now and commissioned in 2010. Each plant is built at a greenfield site in the midwestern United States.

The fossil energy plant cost and performance estimates presented in the study can be used as a baseline for additional comparisons and analyses. These systems analyses are a critical element of planning and guiding Federal Fossil Energy research, development, and demonstration.

Twelve different power plant configurations are analyzed in the Bituminous Baseline Study. These six configurations include integrated gasification combined-cycle (IGCC) cases utilizing General Electric Energy (GEE), ConocoPhillips (CoP), and Shell gasifiers; four pulverized coal (PC) cases, two subcritical and two supercritical, and two natural gas combined-cycle (NGCC) plants. Each configuration was analyzed with and without CCS. The study matrix is provided in Table 1.

Table 1. Study Matrix

Plant Type	Standard Conditions (psig/°F/°F)	Gas Turbine	Gasifier / Boiler	Acid Gas Removal / CO_2 Separation / Sulfur Recovery	CO_2 Capture (%)
IGCC	1,800/1,050/1,050	F-Class	GEE	Selexol/ - /Claus	–
			CoP	MDEA/ - /Claus	–
			Shell	Sulfinol-M/ - /Claus	–
	1,800/1,000/1,000		GEE	Selexol/Selexol/Claus	90
			CoP	Selexol/Selexol/Claus	88
			Shell	Selexol/Selexol/Claus	90
PC	2,400/1,050/1,050	–	Subcritical	Wet flue gas desulfurization (FGD)/ - /Gypsum	–
				Wet FGD/Econamine/Gypsum	90
	3,500/1,100/1,100		Supercritical	Wet FGD/ - /Gypsum	–
				Wet FGD/Econamine/Gypsum	90
NGCC	2,400/1,050/950	F-Class	Heat recovery steam generators	–	–
				- /Econamine/ -	90

Assumptions

Technical

The IGCC cases are dual-train gasification systems. Once the syngas is cleaned of acid gases and other contaminants, it is fed to two advanced F-Class combustion turbines (232 MWe gross output each) coupled with two heat recovery steam generators (HRSGs) and a single steam turbine to generate roughly 750 MWe gross plant output (about 630 MWe, net). The CCS cases require a water-gas-shift (WGS) and a two-stage Selexol system to capture the carbon dioxide (CO_2), as well as compressors to raise the CO_2 to the pipeline requirements of 15.3 MPa (2,215 psia). These CCS systems require a significant amount of extraction steam and auxiliary power, which reduces the output of the steam turbine and reduces the net plant power to about 520 MWe. Because the IGCC system is constrained by the discrete F-Class turbine size, the system cannot be scaled to increase the net output to match that of the cases without CCS.

Table 2. Coal Analysis

Rank	Bituminous	
Seam	Illinois No. 6 (Herrin)	
Source	Old Ben Mine	
Proximate Analysis (weight %)[1]		
	As Received	Dry
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile matter	34.99	39.37
Fixed carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
Higher heating value, Btu/lb	11,666	13,126
Lower heating value, Btu/lb	11,252	12,712

[1]The above proximate analysis assumes sulfur as a volatile matter.

All four PC cases employ a one-on-one configuration comprising a state-of-the-art PC steam generator and steam turbine. The boiler is a dry-bottom, wall-fired unit that employs low-nitrogen oxides (NOx) burners with over-fire air and selective catalytic reduction for NOx control, a wet-limestone, forced-oxidation scrubber for sulfur dioxide (SO_2) and mercury (Hg) control, and a fabric filter for particulate matter (PM) control. In the cases with CCS, the PC plant is equipped with the Econamine FG Plus™ process. The coal feed rate is increased in the CCS cases to increase the gross steam turbine output and account for the higher auxiliary load of carbon capture and compression. The ability of the boiler and steam turbine industry to match unit size to a custom specification has been commercially demonstrated, enabling a common net output of 550 MWe for the PC cases in this study.

Both the IGCC and PC cases utilize Illinois No. 6 bituminous coal. An analysis of the coal used is provided in Table 2.

The NGCC cases use two F-Class turbines, each generating a gross 185 MWe. The two turbines are coupled with two HRSGs and one steam turbine generator in a multi-shaft 2x2x1 configuration. For the CCS cases, CO_2 is removed in an Econamine FG Plus™ process that imposes a significant auxiliary power load on the system and requires significant extraction steam, reducing the steam turbine power output. Similar to the IGCC cases, the NGCC cases are constrained by the combustion turbine size. The NGCC cases have a total net power output of 560 MWe without CCS and 482 MWe with CCS. In all CCS cases, the compressed CO_2 is transported 50 miles via pipeline to a geologic sequestration field for injection into a saline aquifer. In addition to transport and storage, the CO_2 is monitored for 80-years.

Table 3. Environmental Targets

Pollutant	IGCC	PC	NGCC
SO_2	0.0128 lb/MMBtu	0.085 lb/ MMBtu	Negligible
NOx	15 ppmvd @ 15% Oxygen	0.07 lb/MMBtu	2.5 ppmvd @ 15% Oxygen
PM (filterable)	0.0071 lb/MMBtu	0.013 lb/ MMBtu	Negligible
Hg	> 90% capture	1.14 lb/TBtu	N/A

Environmental

The environmental approach for the study was to choose environmental targets for each technology that meet or exceed regulatory requirements. The IGCC targets were chosen to match the design basis of the Electric Power Research Institute for their *CoalFleet for Tomorrow Initiative*. Best Available Control Technology was applied to each of the PC and NGCC cases, and the resulting emissions were compared to 2006 New Source Performance Standards limits and recent permit averages.

Table 4. Major Economic Assumptions

Startup date	2010
Cost year (U.S. dollars)	2007
Coal cost ($/MMBtu)	1.80
Natural gas cost ($/MMBtu)	6.75
Capacity factor (%)	
IGCC	80
PC/NGCC	85
Capital charge factor (%):	
High risk (All IGCC PC/ NGCC with CO_2 capture)	17.5
Low risk (PC/NGCC without CO_2 capture)	16.4
Plant life (years)	30

Economic

The total plant cost (TPC) for each technology was determined through a combination of vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

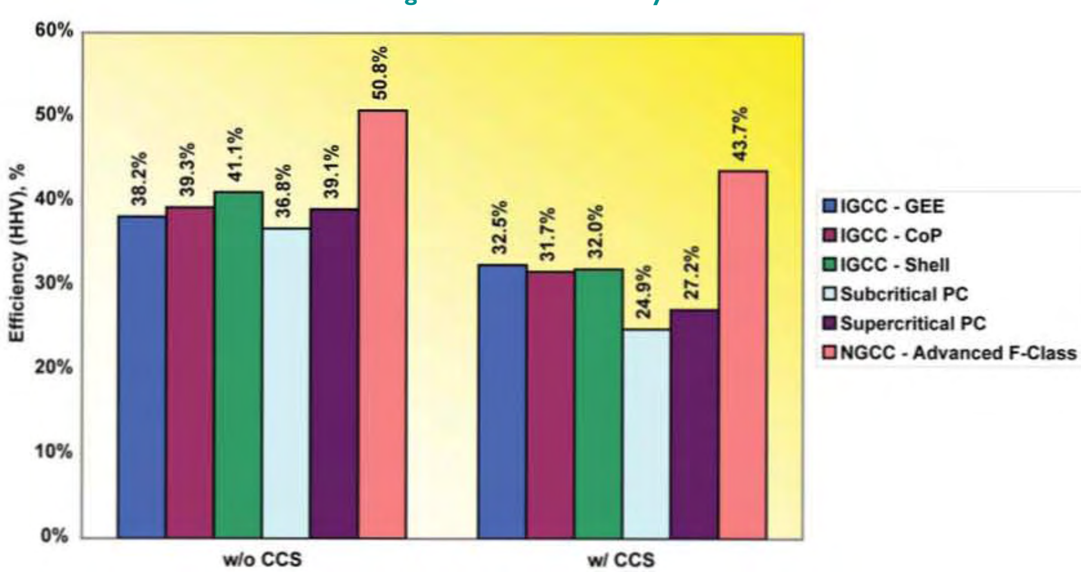
The cost estimates carry an accuracy of ±30 percent, consistent with the screening study level of design engineering applied to the various cases in this study. All cases were evaluated under the same set of technical and economic assumptions allowing meaningful comparisons among the cases evaluated.

Table 4 lists the major economic assumptions. In this study, dual trains were used only when equipment capacity required an additional train, and no redundancy was employed other than normal sparing of rotating equipment.

For those cases that feature CCS, capital and operating costs were estimated for CO_2 transport, storage, and monitoring. These costs were then levelized over a 20-year period.

This study assumes that each new plant would be dispatched at the time it becomes available and would be capable of generating maximum capacity when online. Therefore, capacity factor (CF) is assumed to equal availability. The CF is 80 percent for IGCC cases and 85 percent for both PC and NGCC cases.

Figure 1. Plant Efficiency



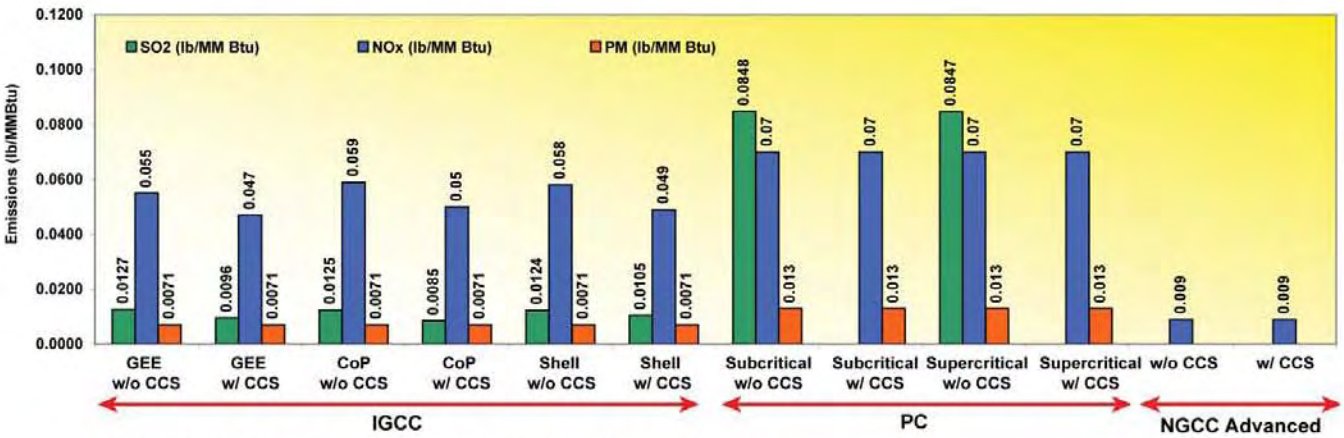
Results

Technical

For cases without CCS, the energy efficiency of NGCC is on the order of 50 percent (higher heating value, HHV basis); followed by supercritical PC and IGCC, both about 40 percent (HHV basis); and subcritical PC, with an efficiency of about 37 percent (HHV basis). Figure 1 shows the relative energy efficiency of each technology case.

With CCS, the energy penalty is 12 percentage points for PC plants, 7 percentage points for NGCC, and 6-9 percentage points for IGCC. Even with CCS, NGCC still maintains the highest efficiency of the plants evaluated at over 40 percent (HHV basis). The significant energy penalty for the PC plants reduces the efficiency to about 26 percent (HHV basis). IGCC has an efficiency advantage over PC in the CCS cases primarily because the CO_2 is more concentrated in IGCC syngas than in PC flue gas, thus requiring less energy to capture. The efficiency of the IGCC plants with CCS is about 32 percent (HHV basis).

Figure 2. SO_2, NOx, and PM Emissions



SO_2 emissions for the PC w/ CCS and the NGCC cases were negligible.
PM emissions for the NGCC cases were negligible

Environmental

All cases meet or exceed the environmental requirements set forth in the study design basis. The NGCC systems are the cleanest types of fossil power plants due to the low sulfur content and lower carbon-to-hydrogen ratio of the methane fuel. IGCC plants are the cleanest coal-based systems, with significantly lower levels of criteria pollutants than the PC plants. Figure 2 compares the results for these pollutant emissions for the various technology cases.

All CCS cases were required to remove 90 percent of the carbon present in the syngas. Due to a higher methane content of the syngas in the CoP case, carbon capture was 88.4 percent. NGCC plants produce 40 percent less CO_2 than the coal-based systems. The uncontrolled coal-based systems emitted as much as 203 lb/MMBtu of CO_2, but with CCS, emissions were reduced to about 20 lb/MMBtu. Figure 3 compares the results for CO_2 emissions for the various technology cases.

All cases were required to control Hg emissions. The environmental target for Hg removal is greater than 90 percent capture for IGCC plants and an emission rate of 1.14 lb/TBtu for PC plants. Figure 4 depicts the Hg emissions results for each case.

Water usage among the plants without CCS is lowest in the NGCC cases. The IGCC plants use about one-and-a-half times as much water as do the NGCC cases, and the PC cases use more than twice the amount of water.

Figure 3. CO_2 Emissions

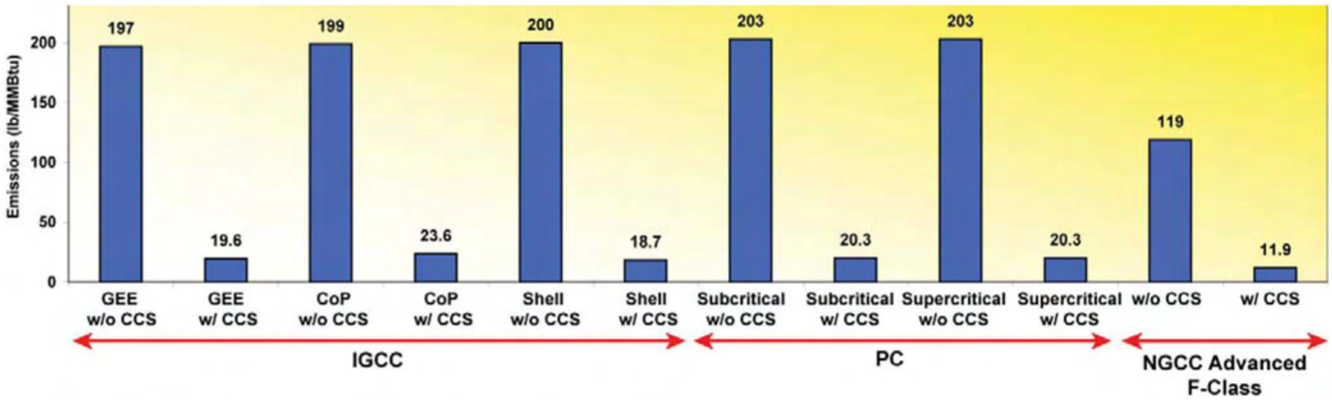
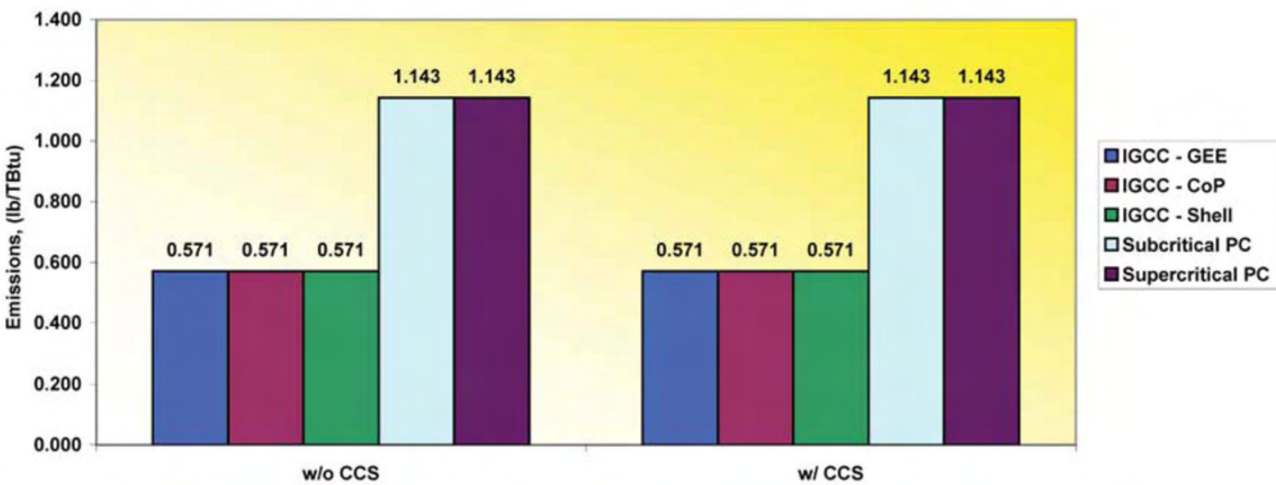
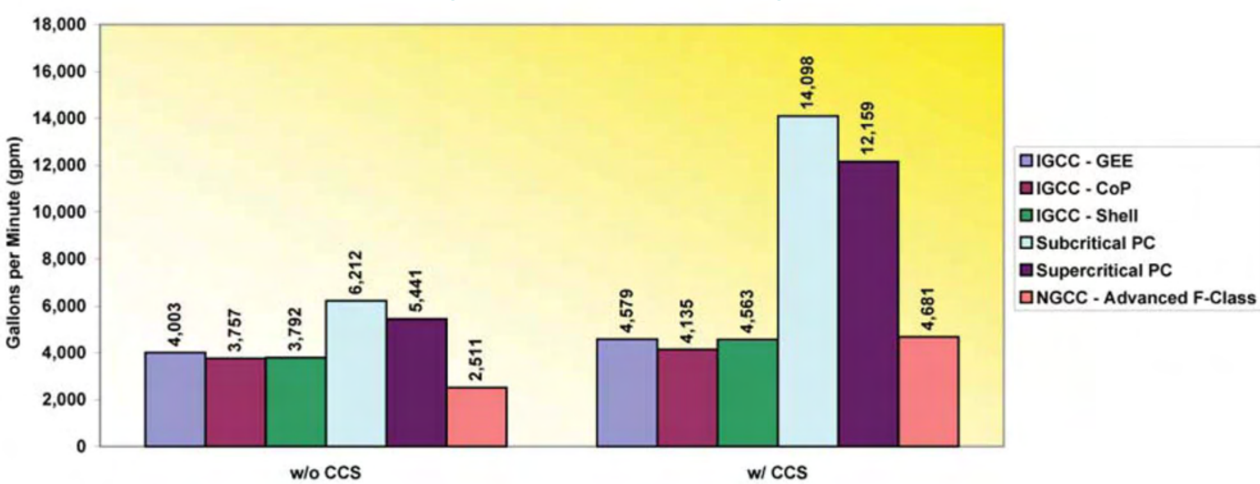


Figure 4. Mercury Emissions



Emissions for the NGCC cases were listed in the report as "Negligible."

Figure 5. Plant Raw Water Usage



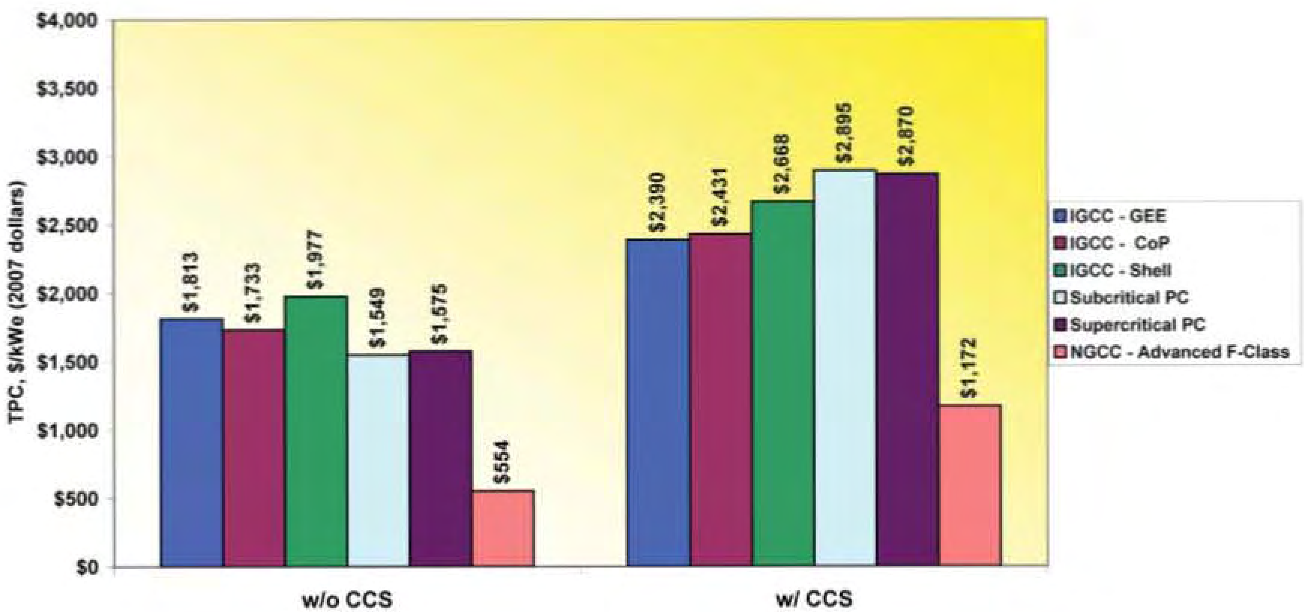
In all CCS cases, water usage increases. Water usage for IGCC cases is similar to an NGCC with CCS, whereas the PC case with CCS plants requires three to four times more water. Figure 5 shows the respective water usage rates for each technology case.

Economic

The coal-based plants have a much higher TPC than NGCC, both with and without CCS. For IGCC, the TPC is about $1,800/kWe, varying somewhat based on the gasifier type. This is about 20 percent higher than the TPC for a PC supercritical plant, which is about $1,500/kWe.

With CCS, the TPC for NGCC and PC plants ($/kW) increases by about 110 and 85 percent respectively. The TPC for the IGCC plant increases by around 35 percent. The NGCC plant capital requirement is over $1,000/kWe, while the IGCC plants cost approximately $2,400 to $2,600/kWe, and the PC plants cost over $2,800/kWe. Figure 6 shows the TPC for each technology case.

Figure 6. Plant Capital Requirements



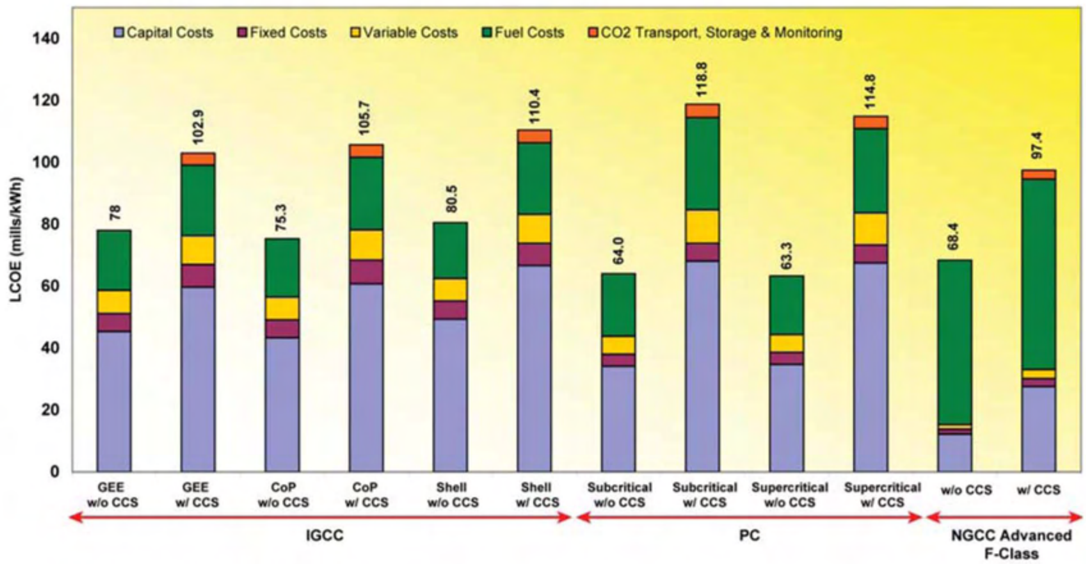
Cost-of-electricity (COE), which accounts for both efficiency and capital cost, is levelized over a 20-year period and expressed in mills/kWh (one mill is one-tenth of a cent). The electricity cost for cases without CCS ranges from about 63 mills/kWh for PC to 68.4 mills/kWh for NGCC and an average of 77.9 mills/kWh for IGCC.

With CCS, IGCC is the least expensive coal-based option for CO_2 removal with a levelized cost-of-electricity (LCOE) ranging from 102.9 mills/kWh to 110.4 mills/kWh. This is about 9 percent lower than PC plants equipped with CCS, which generate electricity at a cost of 114.8 mills/kWh to 118.8 mills/kWh. Figure 7 breaks out the LCOE costs for each technology case.

The cost of CO_2 avoided was calculated for each CCS case and is shown in Figure 8. On an avoided cost of CO_2 basis, IGCC is the least expensive option overall ($32–$42/ton) while NGCC is the most expensive option ($83/ton).

Figure 9 illustrates that at near 80 percent CF, the LCOE for PC cases is less than the LCOE for NGCC cases. With increased CF, the gap in LCOE between IGCC cases and other technologies narrows. For cases with CCS, even at higher CFs, the PC LCOE always for PC cases remains the highest.

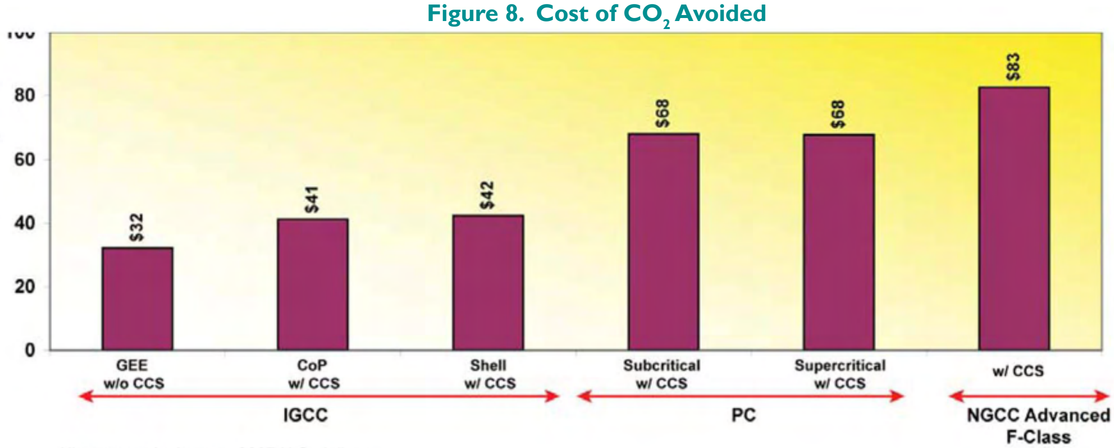
Figure 7. Levelized Cost-of-Electricity



All costs are in January 2007 U.S. dollars.

The LCOE sensitivity to fuel costs for the cases with and without CCS is shown in Figure 10. The solid line is the LCOE of NGCC without CCS as a function of natural gas cost. The dashed line is the LCOE of NGCC with CCS as a function of natural gas cost. The points on the lines represent the natural gas cost that would be required to make the LCOE of NGCC equal to the respective PC or IGCC technologies at a given coal cost.

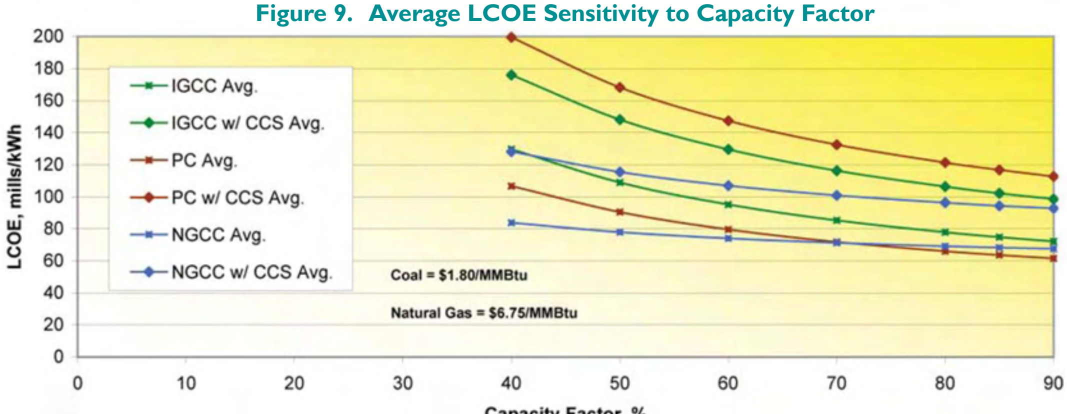
Figure 8. Cost of CO_2 Avoided



All costs are in January 2007 U.S. dollars.

The coal prices shown ($1.35, $1.80, and $2.25/MMBtu) represent the baseline cost and a range of ±25 percent around the baseline.

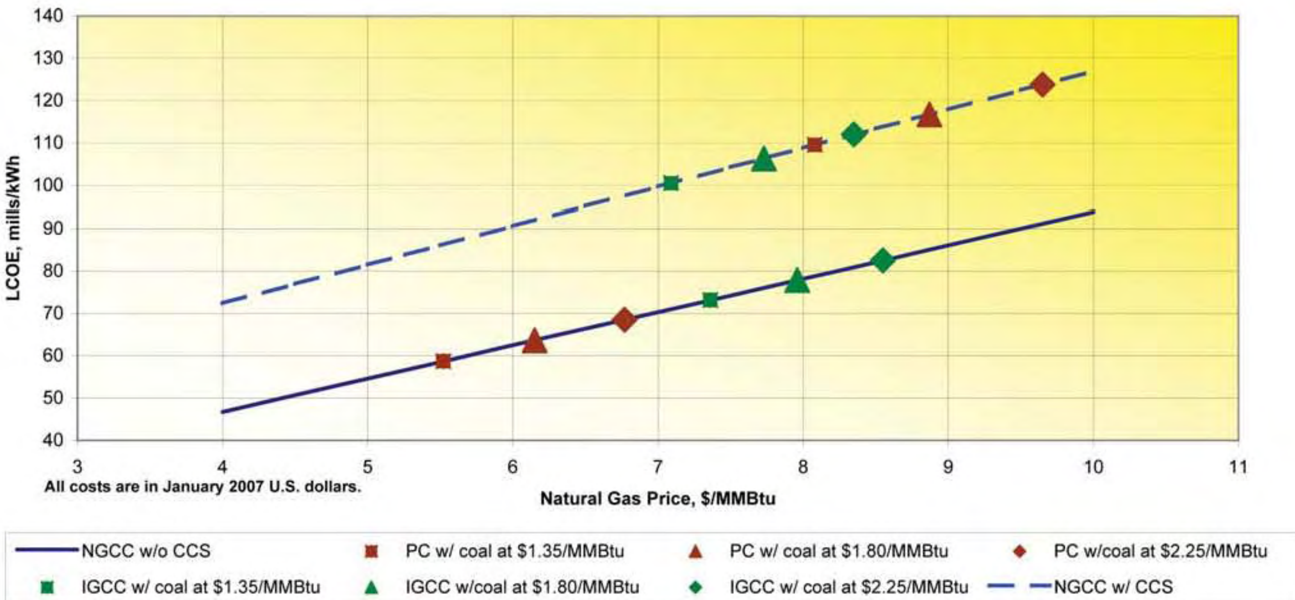
Figure 9. Average LCOE Sensitivity to Capacity Factor



All costs are in January 2007 U.S. dollars.

Without CCS, at the baseline coal cost of $1.80/MMBtu, the LCOE for PC cases equals that of NGCC case at a natural gas price of $6.15/MMBtu; and LCOE for IGCC cases equals that of NGCC case at a gas price of $7.96/MMBtu. With CCS, for the coal-based technologies at a baseline coal cost of $1.80/MMBtu, to be equal to the NGCC case, the cost of natural gas would have to be $7.73/MMBtu (IGCC cases) and $8.87/MMBtu (PC cases).

Figure 10. LCOE Sensitivity to Fuel Costs



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Overview_051507

IGCC Plants With and Without Carbon Capture and Sequestration

Technology Overview

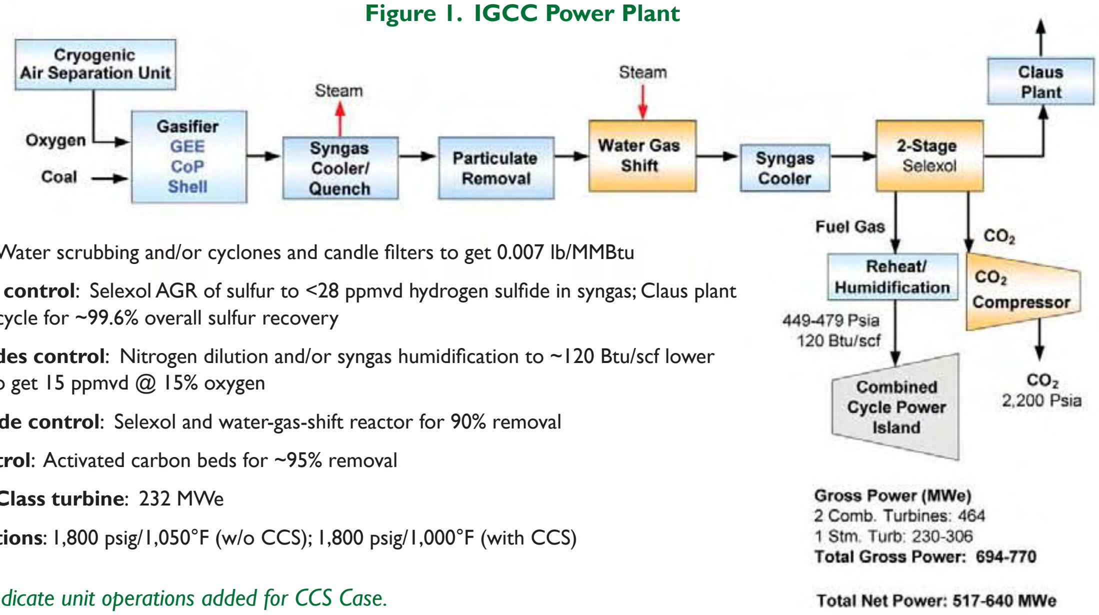
Six Integrated Gasification Combined-Cycle (IGCC) power plant configurations operating on bituminous coal were evaluated and the results are presented in this summary sheet. All cases were analyzed on the same basis, using a consistent set of assumptions and analytical tools. Each gasifier type was assessed with and without carbon capture and sequestration (CCS). The individual configurations are as follows:

- GE Energy (GEE) IGCC plant.
- GEE IGCC plant with CCS.
- ConocoPhillips (CoP) E-Gas™ IGCC plant.
- CoP IGCC plant with CCS.
- Shell IGCC plant.
- Shell IGCC plant with CCS.

Each IGCC design is based on a market-ready technology that is assumed to be commercially available in time to support a 2010 startup date. In cases where equipment or processes have little or no commercial operating experience, a process contingency was added to the cost analysis. The IGCC plants are built at a greenfield site in the midwestern United States and are assumed to operate at 80 percent capacity factor (CF) without sparing of major train components. Nominal plant size (gross rating) is 750 MWe without CCS and 700 MWe with CCS. All designs employ state-of-the-art gasifier technology. The primary fuel is an Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb. Syngas generated in the oxygen (O_2)-blown gasifier is cooled and cleaned prior to being fed to two advanced F-Class combustion turbines. The Brayton cycle is combined with two heat recovery steam generators (HRSGs) and a steam turbine for Rankine cycle power generation. For the CCS cases, a water-gas-shift (WGS) reactor converts carbon monoxide (CO) to carbon dioxide (CO_2), and a two-stage Selexol Acid Gas Removal (AGR) unit separates the hydrogen sulfide and CO_2. After compression, the CO_2 is transported for storage and monitoring.

See Figure 1 for a generic block flow diagram of an IGCC plant. The orange blocks in the figure represent the unit operations added to the configuration for CCS cases.

Figure 1. IGCC Power Plant



PM control: Water scrubbing and/or cyclones and candle filters to get 0.007 lb/MMBtu

Sulfur oxides control: Selexol AGR of sulfur to <28 ppmvd hydrogen sulfide in syngas; Claus plant with tail gas recycle for ~99.6% overall sulfur recovery

Nitrogen oxides control: Nitrogen dilution and/or syngas humidification to ~120 Btu/scf lower heating value to get 15 ppmvd @ 15% oxygen

Carbon dioxide control: Selexol and water-gas-shift reactor for 90% removal

Mercury control: Activated carbon beds for ~95% removal

Advanced F-Class turbine: 232 MWe

Steam conditions: 1,800 psig/1,050°F (w/o CCS); 1,800 psig/1,000°F (with CCS)

Orange blocks indicate unit operations added for CCS Case.

Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

Oxygen-blown, dual-gasifier trains are supplied with Illinois No. 6 bituminous coal. Cryogenic air separation units supply 95 mole percent oxygen to the gasifiers. After being cleaned of particulate matter (PM), mercury (Hg), and sulfur compounds, the syngas is fed to two combustion turbines. The combustion turbines are based on an advanced F-Class design that generates 232 MWe on syngas. With two combustion turbines, the combined gross gas turbine output is 464 MWe.

Nitrogen dilution is used to the maximum extent possible in all cases, and syngas humidification and steam injection are used only if necessary to achieve a syngas lower heating value (LHV) of approximately 120 Btu/scf. The Brayton cycle is integrated with a conventional subcritical steam Rankine cycle consisting of two HRSGs and a steam turbine, operating at 12.4 MPa/566°C/566°C (1,800 psig/1,050°F/1,050°F) in cases without CCS. The two cycles are integrated by use of the combustion turbine exhaust heat for generation of steam in the HRSGs, by feedwater heating in the HRSGs, and by heat recovery from the IGCC process. Recirculating evaporative cooling systems are used for cycle heat rejection. The average efficiency of the cases without CCS is 39.5 percent HHV for a plant with a nominal gross rating of 750 MWe.

The CCS cases require a significant amount of auxiliary power and extraction steam for the process, which reduces the output of the steam turbine in those cases due to a reduction in steam conditions to 12.4 MPa/538 °C/538°C (1,800 psig/1,000°F/1,000°F). The lower main and reheat steam temperature is due to reduced turbine firing temperature. Although the reduced firing temperature allows for more reliable operation with a high-hydrogen content fuel, it also results in a lower turbine exhaust temperature. This results in a lower nominal gross plant output for the CCS cases of about 700 MWe, for an average net plant efficiency of 32 percent (HHV basis).

The nominal 90 percent CO_2 reduction is accomplished by adding sour-gas-shift (SGS) reactors to convert CO to CO_2 and using a two-stage Selexol process with a second stage CO_2 removal efficiency of up to 95 percent, a number that was supported by vendor quotes. In the GEE CO_2 capture case, two stages of SGS and a Selexol removal efficiency of 92 percent were required, which resulted in 90.2 percent reduction of CO_2 in the syngas. The CoP capture case required three stages of SGS and 95 percent capture in the Selexol process, which resulted in 88.4 percent reduction of CO_2 in the syngas. In the CoP case, the capture target of 90 percent could not be achieved because of the high syngas methane content (3.5 volume percent (vol%) compared to 0.10 vol% in the GEE gasifier and 0.04 vol% in the Shell gasifier). The Shell capture case required two stages of SGS and 95 percent capture in the Selexol process, which resulted in 90.8 percent reduction of CO_2 in the syngas.

Once captured, the CO_2 is dried and compressed to 15.3 MPa (2,215 psia). The compressed CO_2 is transported via pipeline to a geologic sequestration field for injection into a saline aquifer, which is located within 50 miles of the plant. Therefore, CO_2 transport, storage, and monitoring costs are included in the analyses.

Fuel Analysis and Costs

All IGCC coal-fired cases were modeled using Illinois No. 6 coal, characterized by the proximate analysis shown in Table 1.

Table 1. Fuel Analysis

Rank	Bituminous	
Seam	Illinois No. 6 (Herrin)	
Source	Old Ben Mine	
Proximate Analysis (weight %)[1]		
	As Received	Dry
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile matter	34.99	39.37
Fixed carbon	44.19	49.72
Total	**100.00**	**100.00**
Sulfur	2.51	2.82
Higher heating value, Btu/lb	11,666	13,126
Lower heating value, Btu/lb	11,252	12,712

[1]The above proximate analysis assumes sulfur as a volatile matter.

A cost of $1.80/MMBtu (January 2007 dollars) was determined from the Energy Information Administration AEO2007 for an eastern interior high-sulfur bituminous coal.

Environmental Design Basis

The environmental approach for this study was to evaluate each of the IGCC cases on the same regulatory design basis. The environmental specifications for a greenfield IGCC plant are based on the Electric Power Research Institute (EPRI) *CoalFleet User Design Basis for Coal-Based IGCC Plants* specification. Table 2 provides details of the environmental design basis for IGCC plants built at a midwestern location. The emission controls assumed for each of the six IGCC cases are as follows:

Table 2. Environmental Targets

Pollutant	IGCC
SO_2	0.0128 lb/MMBtu
NOx	15 ppmvd @ 15% Oxygen
PM (filterable)	0.0071 lb/MMBtu
Hg	>90% capture

- Selexol, Sulfinol-M, or refrigerated methyldiethanolamine AGR in combination with a Claus plant are used for sulfur dioxide (SO_2) control in the GEE, Shell, and CoP cases without CCS, respectively.
- A two-stage Selexol process was used for AGR and CO_2 control in all CCS cases.
- Nitrogen dilution is used for nitrogen oxides (NOx) control to the maximum extent possible, and humidification and steam injection are used to obtain the required syngas heating value, if required.
- Water scrubbing and/or cyclones and candle filters were used for PM control.
- Activated carbon beds were used for Hg removal.

Major Economic and Financial Assumptions

For the IGCC cases, estimates of capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates were developed for each plant based on adjusted vendor-furnished and actual cost data from recent design/build projects. These costs resulted in determination of a revenue requirement for a 20-year LCOE based on the power plant costs and assumed financing structure. Listed in Table 3 are the major economic and financial assumptions for the IGCC cases.

Table 3. Major Economic and Financial Assumptions for IGCC Cases

Major Economic Assumptions	
Capacity factor	80%
Costs per year, constant U.S. dollars	2007 (January)
Illinois No. 6 coal delivered cost	$1.80/MMBtu
Construction period	3 years
Plant startup date	2010 (January)
Major Financial Assumptions	
Depreciation	20 years
Federal income tax	34%
State income tax	6%
After tax weighted cost of capital	9.67%
Capital structure:	
Common equity Debt	55% (Cost = 12%) 45% (Cost = 11%)
Capital charge factor	17.5%

Project contingencies were added to each of the cases to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was an average of 13.4 percent for the IGCC cases without CCS and an average of 13.8 percent for the IGCC cases with CCS.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies have been applied to the estimates as follows:

- Slurry Prep and Feed – 5 percent on GE IGCC cases.
- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases.
- Two Stage Selexol – 20 percent on all IGCC cases with CCS.
- Mercury Removal – 5 percent on all IGCC cases.

- Combustion Turbine Generator – 5 percent on all IGCC cases without CCS; 10 percent on all IGCC cases with CCS.
- Instrumentation and Controls – 5 percent on all IGCC cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 80 percent for IGCC cases. The assumed capacity factor for IGCC is 80 percent.

For the IGCC cases that feature CCS, capital and operating costs were estimated for transporting CO_2 to an underground storage field, associated storage in a saline aquifer, and for monitoring beyond the expected life of the plant. These costs were then levelized over a 20-year period.

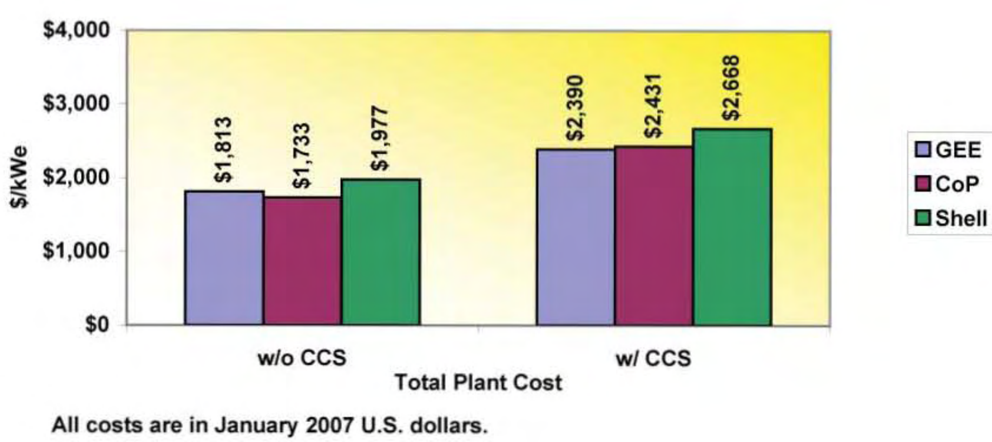
Results

An analysis of the six IGCC cases is presented in the following subsections.

Capital Cost

The total plant cost (TPC) for each of the six IGCC cases is compared in Figure 2. The TPC includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

Figure 2. Comparison of TPC for the Six IGCC Cases



The results of the analysis indicate that the Shell IGCC costs about $244/kWe more than the CoP IGCC without CCS. With CCS, the TPC increases by roughly 32–40 percent for the range of IGCC cases, resulting in a spread of capital costs from $2,390/kWe to $2,668/kWe. The Shell IGCC still remains the highest capital cost configuration.

Efficiency

The net plant HHV efficiencies for the six IGCC cases are compared in Figure 3. This analysis indicates that, in the cases without CCS, the Shell plant efficiency of 41.1 percent HHV is almost 3 percentage points higher than the GEE case. With CCS cases, the efficiency penalty is a 5.7 to 9 percentage point HHV drop in all IGCC plant cases, resulting in an average efficiency of roughly 32 percent HHV.

Figure 3. Comparison of Net Plant Efficiency for the Six IGCC Cases

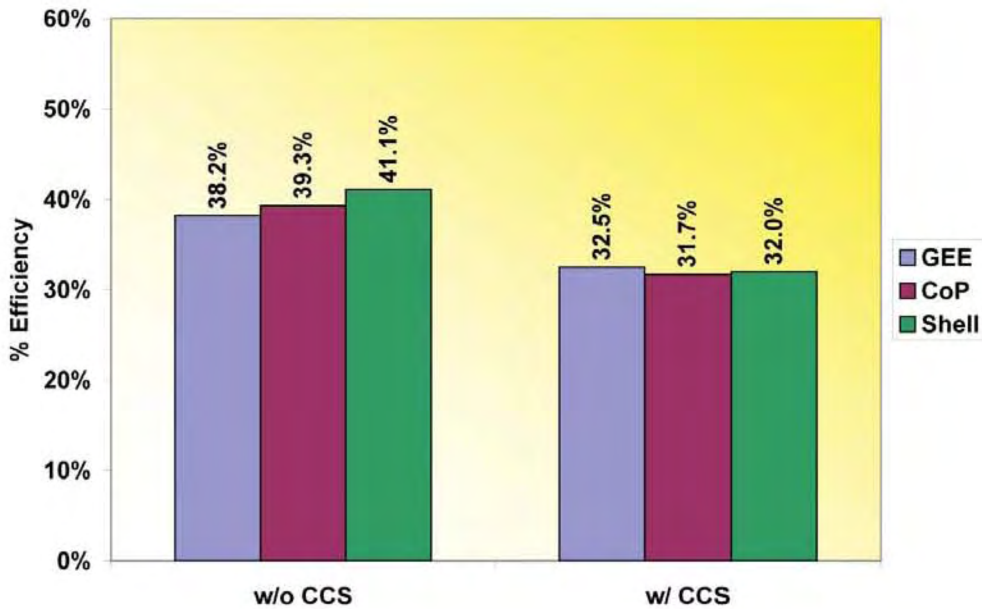
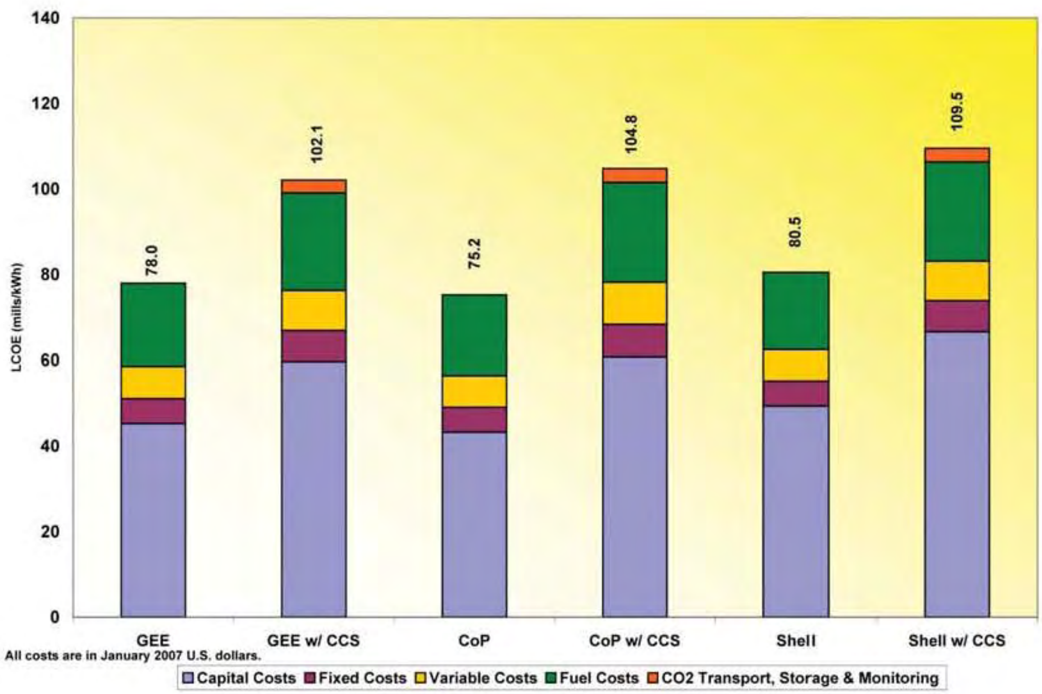


Figure 4. Comparison of Levelized Cost-of-Electricity for the Six IGCC Cases



The LCOE is a measurement of the coal-to-busbar cost of power, and includes the TPC, fixed and variable operating costs, and fuel costs levelized over a 20-year period. The calculated cost of transport, storage, and monitoring for CO_2 is about $4.30/short ton, which adds an average of 4 mills to the LCOE.

The IGCC plants generate power at an LCOE of about 78 mills/kWh at a CF of 80 percent. When CCS is included, the increased TPC and reduced efficiency result in a higher LCOE of roughly 106 mills/kWh.

Environmental Impacts

Table 4 indicates that the emissions from all six IGCC plants evaluated meet or exceed EPRI's *CoalFleet User Design Basis for Coal-Based IGCC Plants* specification. Carbon dioxide emissions are reduced by 90 percent in the capture cases, resulting in less than 460,000 tons/year of CO_2 emissions. The cost of CO_2 avoided is defined as the difference in the 20-year LCOE between controlled and uncontrolled like cases, divided by the difference in CO_2 emissions in kg/MWh. In these analyses, the cost of CO_2 avoided ranges from $32/ton to $42/ton. Raw water usage in both cases with and without CCS is roughly 4,000 gpm.

Table 4. Comparative Emissions for the Six IGCC Cases @ 80% Capacity Factor

Pollutant	IGCC					
	GEE		CoP		Shell	
	Without CCS	With CCS (90%)	Without CCS	With CCS (90%)	Without CCS	With CCS (90%)
CO_2						
• tons/year	3,937,728	401,124	3,777,815	460,175	3,693,990	361,056
• lb/MMBtu	197	19.6	199	23.6	200	18.7
• cost of CO_2 avoided ($/ton)	---	32	---	41	---	42
SO_2						
• tons/year	254	196	237	167	230	204
• lb/MMBtu	0.0127	0.0096	0.0125	0.0085	0.0124	0.0105
NOx						
• tons/year	1,096	955	1,126	972	1,082	944
• lb/MMBtu	0.055	0.047	0.059	0.050	0.058	0.049
PM						
• tons/year	142	145	135	139	131	137
• lb/MMBtu	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071
Hg						
• tons/year	0.011	0.012	0.011	0.011	0.011	0.011
• lb/TBtu	0.571	0.571	0.571	0.571	0.571	0.571
Raw water usage, gpm	4,003	4,579	3,757	4,135	3,792	4,563

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.
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GE Energy IGCC Plant

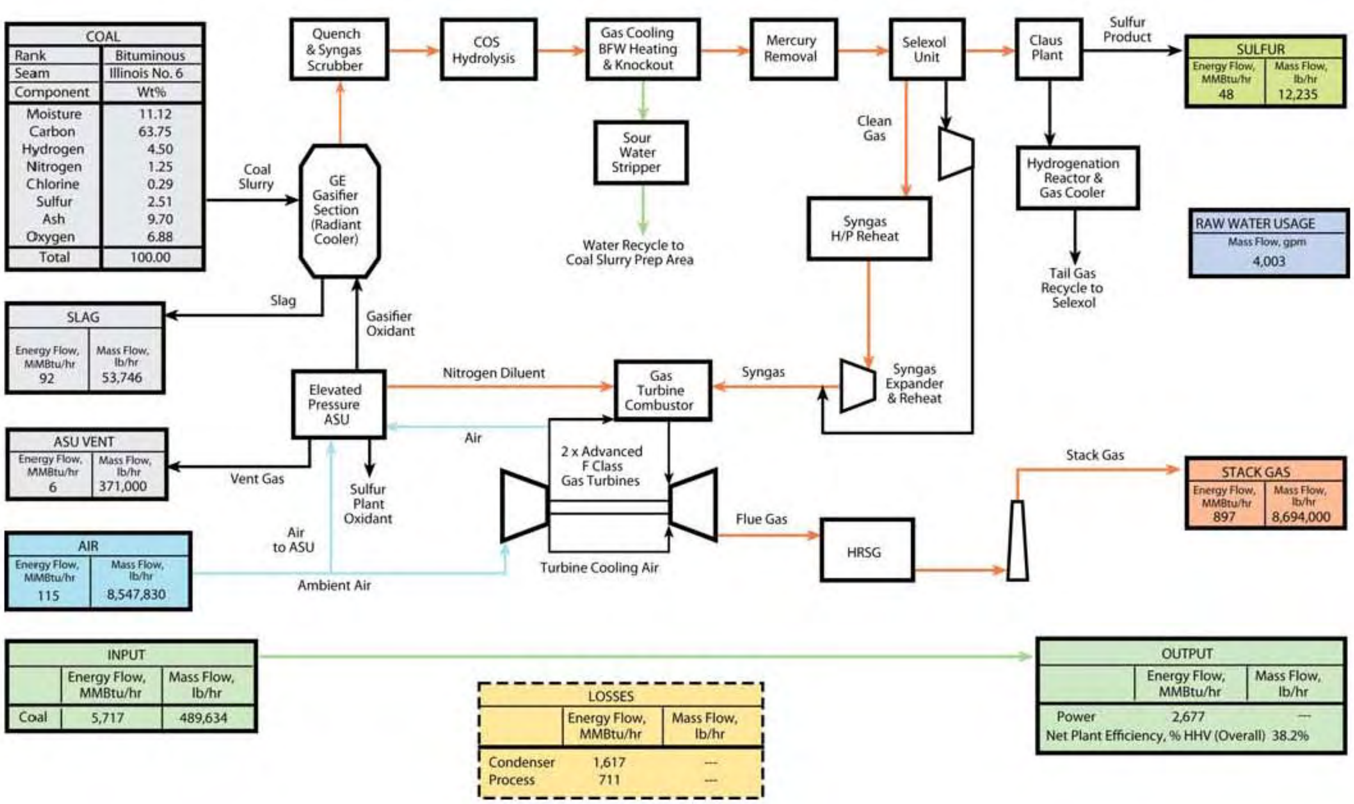
Plant Overview

This analysis is based on a 640 MWe (net power output) Integrated Gasification Combined-Cycle (IGCC) plant using GE Energy (GEE) radiant-only gasification technology, located at a greenfield site in the midwestern United States. The radiant-only configuration consists of a radiant synthesis gas cooler followed by a water quench. Two pressurized, slurry-fed, entrained flow gasification trains feed two advanced F-Class combustion turbines. Two heat recovery steam generators (HRSGs) and one steam turbine provide additional power. The combination process and heat and mass balance diagram for the GEE IGCC plant is shown in Figure 1. The primary fuel is an Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb. The capacity factor (CF) for the plant is 80 percent without sparing of major train components. A summary of plant performance data for the GEE IGCC plant is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	GEE IGCC
Carbon capture	No
Net power output (kWe)	640,250
Net plant HHV efficiency (%)	38.2
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 80% capacity factor	78.0

Figure 1. Process Flow Diagram GEE IGCC



Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

The plant uses an improved version of the GEE gasification technology (formerly licensed by Chevron Corp. and predecessor company Texaco Inc.), which is currently in operation at the 250 MWe Tampa Electric IGCC plant in Polk County, FL. All technology selected in the plant design is assumed to be available to facilitate a 2010 startup date for anewly constructed plant. A summary of performance for an advanced F-Class combustion turbine for the GEE IGCC plant is presented in Table 2.

Table 2. Advanced Gas Turbine Performance[1]

	Advanced F-Class
Net output, MWe	185
Pressure ratio	18.5
Airflow, kg/s (lb/s)	431 (950)
Firing temperature°C (°F)	>1,371 (>2,500)

[1]At International Standards Organization conditions firing natural gas. Performance information for syngas firing is not available.

Two gasification trains process a total of 5,876 tons of coal per day. A slurry (63 percent by weight coal) is transferred from the slurry storage tank to the gasifier with a high-pressure pump. Oxygen (O_2) is produced in a cryogenic air separation unit. The coal slurry and O_2 react in the gasifier at about 5.6 MPa (815 psia) at a high temperature (in excess of 1,316°C [2,400°F]) to produce syngas. Hot syngas and molten solids from the reactor flow downward into a radiant heat exchanger, where the syngas is cooled to 593°C (1,100°F) and the ash solidifies. Raw syngas continues downward into a quench system where most of the particulate matter (PM) is removed and then into the syngas scrubber where most of the remaining entrained solids are removed along with ammonia. Slag captured by the quench system is recovered in a slag recovery unit. The gas goes through a series of additional gas coolers and cleanup processes, including a carbonyl sulfide hydrolysis reactor, a carbon bed for mercury (Hg) removal, and a Selexol-based acid gas removal (AGR) plant.

A Brayton cycle, fueled by syngas, is used in conjunction with a conventional subcritical steam Rankine cycle for combined-cycle power generation. Compressed nitrogen from the air separation unit is used for syngas dilution, which aids in minimizing the formation of nitrogen oxides (NOx) during combustion in the gas turbine burner section. The limiting factor that determines the use of a subcritical steam cycle is the maximum design pressure of 12.4 MPa (1,800 psig), which can be tolerated in the GEE radiant cooler. The two cycles are integrated by generation of steam in the HRSGs, by feedwater heating in the HRSGs, and by heat recovery from the IGCC process (radiant syngas cooler). The HRSG/steam turbine cycle is 12.4 MPa/566°C/566°C (1,800 psig/1,050°F/1,050°F). The plant produces a net output of 640 MWe. The summary of plant electrical generation performance is presented in Table 3. This configuration results in a net plant efficiency of 38.2 percent (HHV basis), or a net HHV heat rate of 8,922 Btu/kWh.

Table 3. Plant Electrical Generation

	Electrical Summary
Advanced gas turbine x 2, MWe	464.3
Steam turbine, MWe	298.9
Sweet gas expander, MWe	7.1
Gross power output, MWe	770.3
Auxiliary power requirement, MWe	(130.1)
Net power output, MWe	640.2

Environmental Performance

The environmental specifications for a greenfield IGCC plant are based on the Electric Power Research Institute *CoalFleet User Design Basis for Coal-Based IGCC Plants* specification. Low sulfur dioxide (SO_2) emissions (less than 4 ppmv in the flue gas) are achieved by capture of the sulfur in the Selexol AGR process, which removes over 99 percent of the sulfur in the fuel gas. The resulting hydrogen sulfide-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. Nitrogen oxides emissions are limited by nitrogen dilution in the gas turbine combustor to 15 ppmvd (as nitrogen oxide at 15 percent O_2). Filterable PM discharge to the atmosphere is limited by the use of the syngas quench in addition to the syngas scrubber and the gas-washing effect of the AGR absorber. Ninety-five percent of the Hg is captured from the syngas by an activated carbon bed.

A summary of the resulting air emissions for the GEE IGCC plant is presented in Table 4.

Cost Estimation

Plant size, primary/secondary fuel type, construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date were used to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant were based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 5.

Table 4. Air Emissions Summary @ 80% Capacity Factor

Pollutant	GEE IGCC Without CSS
CO_2	
• tons/year	3,937,728
• lb/MMBtu	197
• cost of CO_2 avoided	N/A
SO_2	
• tons/year	254
• lb/MMBtu	0.0127
NOx	
• tons/year	1,096
• lb/MMBtu	0.055
PM (filterable)	
• tons/year	142
• lb/MMBtu	0.0071
Hg	
• tons/year	0.011
• lb/TBtu	0.571

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 13.3 percent of the GEE IGCC case TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 2.5 percent of the GEE IGCC case TPC and have been applied to the estimates as follows:

- Slurry Prep and Feed – 5 percent on GE IGCC cases.
- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases.
- Mercury Removal – 5 percent on all IGCC cases.
- Combustion Turbine Generator – 5 percent on all IGCC cases without CCS.
- Instrumentation and Controls – 5 percent on all IGCC cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 80 percent for IGCC cases.

The 640 MWe (net) GEE IGCC plant was projected to have a TPC of $1,813/kWe, resulting in a 20-year LCOE of 78 mills/kWh.

Table 5. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions						
Case:	**1x640 MWe net GEE IGCC**					
Plant Size:	640.3	(MWe, net)	Heat Rate:	8,922	(Btu/kWh)	
Primary/Secondary Fuel (type):	Illinois #6 Coal		Fuel Cost:	1.80	($/MMBtu)	
Construction Duration:	3	(years)	Plant Life:	30	(years)	
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)	
Capacity Factor:	80	(%)	Capital Charge Factor:	17.5	(%)	
Resulting Capital Investment (Levelized 2007 dollars)						**Mills/kWh**
Total Plant Cost						43.3
Resulting Operating Costs (Levelized 2007 dollars)[3]						**Mills/kWh**
Fixed Operating Cost						5.8
Variable Operating Cost						7.5
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu						**Mills/kWh**
						19.4
Total Levelized Busbar Cost of Power (2007 dollars)						**Mills/kWh**
						78.0

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

[3]No credit taken for by-product sales.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.

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GE Energy IGCC Plant With Carbon Capture & Sequestration

Plant Overview

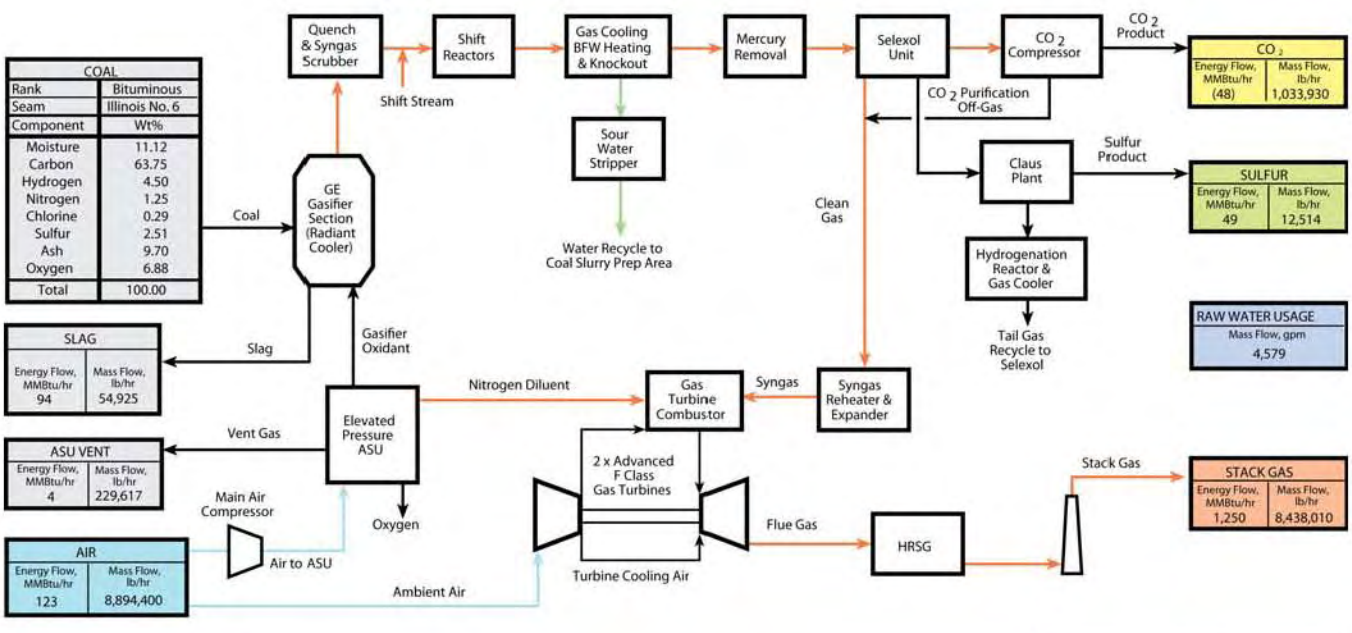
This analysis is based on a 556 MWe (net power output) Integrated Gasification Combined-Cycle (IGCC) plant, using GE Energy (GEE) radiant-only gasification technology, located at a greenfield site in the midwestern United States. The plant utilizes carbon capture and sequestration (CCS). Two pressurized, slurry-fed, entrained-flow gasification trains, utilizing water-gas–shift (WGS) reactors, feed two advanced F-Class combustion turbines. Two heat recovery steam generators (HRSGs) and one steam turbine provide additional power. Carbon dioxide (CO_2) is removed with the two-stage Selexol physical solvent process. The combination process and heat and mass balance diagram for the GEE IGCC plant with CCS case is shown in Figure 1. The primary fuel is an Illinois No. 6 bituminous coal with an assumed higher heating value (HHV) of 11,666 Btu/lb. The capacity factor (CF) for the plant is 80 percent without sparing of major train components. A summary of plant performance data for the GEE IGCC plant with CCS case is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	GEE IGCC
Carbon capture	Yes
Net power output (kWe)	555,675
Net plant HHV efficiency (%)	32.5
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 80% capacity factor	102.9
Total plant cost ($ x 1,000)	$1,328,209
Cost of CO_2 avoided[1] ($/ton)	32

[1]The cost of CO_2 avoided is defined as the difference in the 20-year levelized cost-of-electricity between controlled and uncontrolled like cases, divided by the difference in CO_2 emissions in kg/MWh.

Figure 1. Process Flow Diagram
GEE IGCC with CCS



INPUT	Energy Flow, MMBtu/hr	Mass Flow, lb/hr
Coal	5,842	500,379

LOSSES	Energy Flow, MMBtu/hr	Mass Flow, lb/hr
Condenser	1,431	—
Process	847	—

OUTPUT	Energy Flow, MMBtu/hr	Mass Flow, lb/hr
Power	2,587	—
Net Plant Efficiency, % HHV (Overall)	32.5%	

Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

The plant uses an improved version of the GEE gasification technology (formerly licensed by Chevron Corp. and predecessor company Texaco Inc.), which is currently in operation at the 250 MWe Tampa Electric IGCC plant in Polk County, FL. All technology selected for the plant design is assumed to be available to facilitate a 2010 startup date for a newly constructed plant. A summary of performance for the advanced F-Class combustion turbine for the GEE IGCC plant with CCS is presented in Table 2.

Table 2. Advanced Gas Turbine Performance[1]

	Advanced F-Class
Net output, MWe	185
Pressure ratio	18.5
Airflow, kg/s (lb/s)	431 (950)
Firing temperature, °C (°F)	>1,371 (>2,500)

[1]At International Standards Organization conditions firing natural gas. Performance information for syngas firing is not available.

Two gasification trains process a total of 6,005 tons of coal per day. A slurry (63 percent by weight coal) is transferred from the slurry storage tank to the gasifier with a high-pressure pump. Oxygen (O_2) is produced in a cryogenic air separation unit. The coal slurry and O_2 react in the gasifier at about 5.6 MPa (815 psia) at a high temperature (in excess of 1,316°C [2,400°F]) to produce syngas. Hot syngas and molten solids from the reactor flow downward into a radiant heat exchanger, where the syngas is cooled to 593°C (1,100°F) and the ash solidifies. Raw syngas continues downward into a quench system where most of the particulate matter (PM) is removed and then into the syngas scrubber where most of the remaining entrained solids are removed along with halogens and ammonia. Slag captured by the quench system is recovered in a slag recovery unit. The gas goes through a series of additional gas coolers and cleanup processes, including a carbon bed for mercury (Hg) removal.

To capture CO_2, a WGS reactor containing a series of two shifts with intercooled stages converts a nominal 96 percent of the carbon monoxide to CO_2. Carbon dioxide is removed from the cool, particulate-free gas stream with Selexol solvent. The dual-absorber Selexol acid gas removal (AGR) process preferentially removes hydrogen sulfide (H_2S) as a product stream, leaving CO_2 as a separate product stream. The CO_2 is dried and compressed to 15.3 MPa (2,215 psia) for subsequent pipeline transport. The compressed CO_2 is transported via pipeline to a geologic sequestration field for injection into a saline aquifer, which is located within 50 miles of the plant.

A Brayton cycle, fueled by the syngas, is used in conjunction with a conventional subcritical steam Rankine cycle for combined-cycle power generation. The limiting factor that determines the use of a subcritical steam cycle is the maximum design pressure of 12.4 MPa (1,800 psig), which can be tolerated in the GEE radiant cooler. The two cycles are integrated by generation of steam in the HRSGs, by feedwater heating in the HRSGs, and by heat recovery from the IGCC process (radiant syngas cooler). The HRSG/steam turbine cycle is 12.4 MPa/538°C/538°C (1,800 psig/1,000°F/1,000°F). The plant produces a net output of 555.7 MWe. The summary of plant electrical generation performance is presented in Table 3. This configuration results in a net plant efficiency of 32.5 percent (HHV basis), or a net plant HHV heat rate of 10,505 Btu/kWh.

Table 3. Plant Electrical Generation

	Electrical Summary
Advanced gas turbine x 2, MWe	464.0
HRSG steam turbine, MWe	274.7
Sweet gas expander, MWe	6.3
Gross power output, MWe	745.0
Auxiliary power requirement, MWe	(189.3)
Net power output, MWe	555.7

Environmental Performance

The environmental specifications for a greenfield IGCC plant are based on the Electric Power Research Institute *CoalFleet User Design Basis for Coal-Based IGCC Plants* specification. Low sulfur dioxide (SO_2) emissions (3 ppm in the flue gas) are achieved by capture of the sulfur in the Selexol AGR process, which removes 99 percent of the sulfur in the fuel gas. The resulting H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. Nitrogen oxides (NOx) emissions are limited by nitrogen dilution in the gas turbine combustor to 15 ppmvd (as nitrogen oxide at 15 percent O_2). Particulate discharge to the atmosphere is limited by the use of the syngas quench in addition to the syngas scrubber and the gas-washing effect of the AGR absorber. Ninety-five percent of the Hg is captured from the syngas by an activated carbon bed. Ninety percent of the CO_2 from the syngas is captured in the AGR system and compressed for pipeline transport and sequestration.

A summary of the resulting air emissions for the GEE IGCC plant with CCS is presented in Table 4.

Table 4. Air Emissions Summary @ 80% Capacity Factor

Pollutant	GEE IGCC with CCS (90%)
CO_2	
• tons/year	401,124
• lb/MMBtu	19.6
• cost of CO_2 avoided ($/ton)	32
SO_2	
• tons/year	196
• lb/MMBtu	0.0096
NOx	
• tons/year	955
• lb/MMBtu	0.047
PM (filterable)	
• tons/year	145
• lb/MMBtu	0.0071
Hg	
• tons/year	0.012
• lb/TBtu	0.571

Cost Estimation

Plant size, primary/secondary fuel type, design/construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date were used as inputs to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant were based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 5.

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 13.6 percent of the GEE IGCC with CCS case TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 4.2 percent of the GEE IGCC with CCS case TPC and have been applied to the estimates as follows:

- Slurry Prep and Feed – 5 percent on GE IGCC cases.
- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases.
- Two Stage Selexol – 20 percent on all IGCC CCS cases.
- Mercury Removal – 5 percent on all IGCC cases.
- Combustion Turbine Generator – 10 percent on all IGCC cases with CCS.
- Instrumentation and Controls – 5 percent on all IGCC cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 80 percent for IGCC cases.

The calculated cost of transport, storage, and monitoring for CO_2 is $4.20/short ton, which adds 3.9 mills/kWh to the LCOE.

The 556 MWe (net) GEE IGCC plant with CCS was projected to have a TPC of $2,390/kWe, resulting in a 20-year LCOE of 102.9 mills/kWh.

Table 5. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions					
Case:	1x556 MWe net GEE IGCC with CCS				
Plant Size:	555.7	(MWe, net)	Heat Rate:	10,505	(Btu/kWh)
Primary/Secondary Fuel (type):	Illinois #6 Coal		Fuel Cost:	1.80	($/MMBtu)
Construction Duration:	3	(years)	Plant Life:	30	(years)
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)
Capacity Factor:	80	(%)	Capital Charge Factor:	17.5	(%)
Resulting Capital Investment (Levelized 2007 dollars)					**Mills/kWh**
Total Plant Cost					59.7
Resulting Operating Costs (Levelized 2007 dollars)[3]					**Mills/kWh**
Fixed Operating Cost					7.2
Variable Operating Cost					9.4
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu					**Mills/kWh**
					22.8
Resulting Levelized CO_2 Cost (2007 dollars)					**Mills/kWh**
					3.9
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					102.9

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

[3]No credit taken for by-product sales.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.

B_IG_GEE_CCS_051507

ConocoPhillips E-Gas™ IGCC Plant

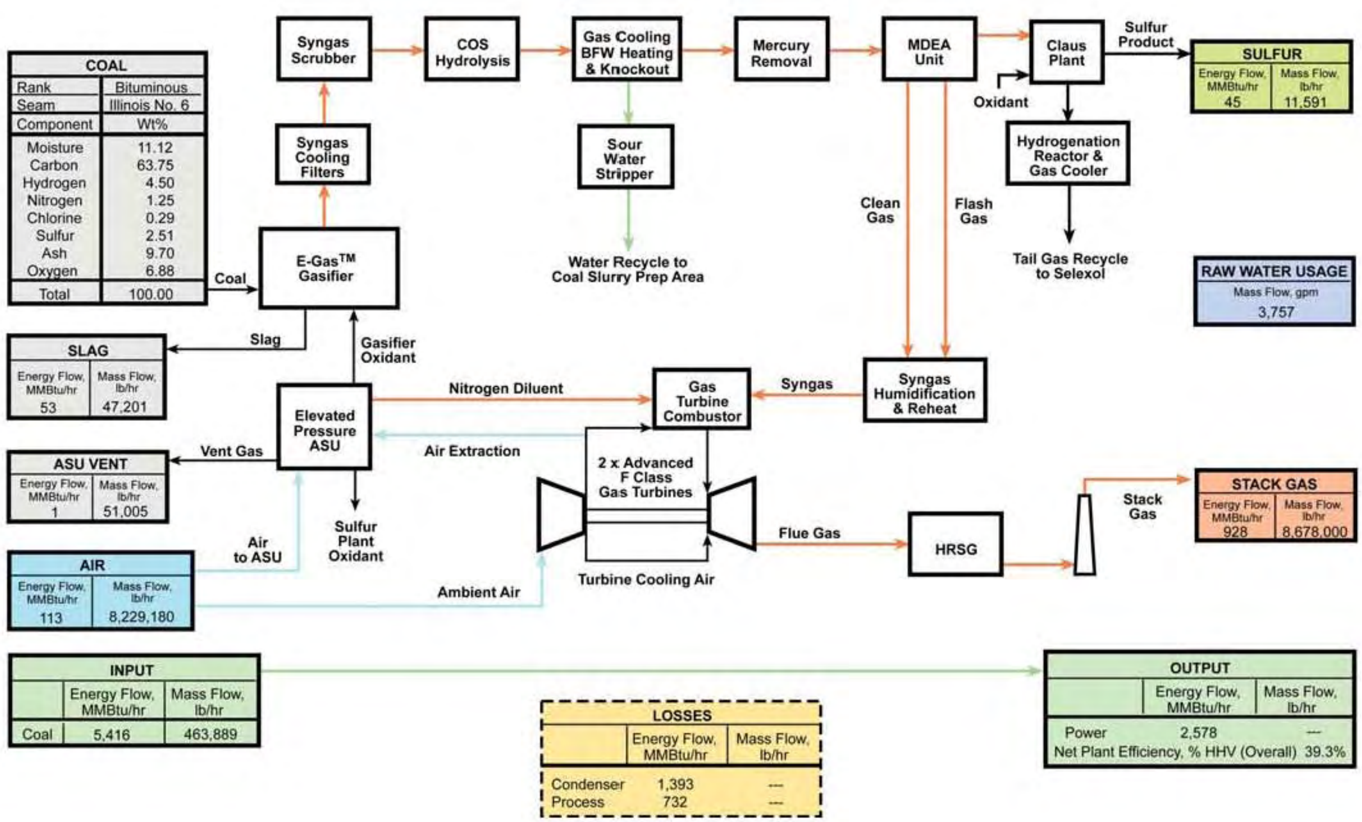
Plant Overview

This analysis is based on a 623 MWe (net power output) Integrated Gasification Combined-Cycle (IGCC) plant, using ConocoPhillip E-Gas™ gasification technology, located at a greenfield site in the midwestern United States. Two pressurized entrained-flow, two-stage gasification trains feed two advanced F-Class combustion turbines. Two heat recovery steam generators (HRSGs) and one steam turbine provide additional power. The combination process and heat and mass balance diagram for the CoP IGCC plant is shown in Figure 1. The primary fuel is an Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb. The capacity factor (CF) for the plant is 80 percent without sparing of major train components. A summary of plant performance data for the CoP IGCC plant is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	CoP IGCC
Carbon capture	No
Net power output (kWe)	623,370
Net plant HHV efficiency (%)	39.3
Primary fuel	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 80% capacity factor	75.3
Total plant cost ($ x 1,000)	$1,080,166

Figure 1. Process Flow Diagram
CoP IGCC



Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

The plant uses an improved version of the CoP gasification technology, which is currently in operation at the PSI Energy Inc. 265 MWe Wabash River IGCC plant near West Terre Haute, IN. All technology selected in the plant design is assumed to be available to facilitate a 2010 startup date for a newly constructed plant. A summary of performance for the advanced F-Class combustion turbine for the CoP IGCC plant is presented in Table 2.

Table 2. Advanced Gas Turbine Performance[1]

	Advanced F-Class
Net output, MWe	185
Pressure ratio	18.5
Airflow, kg/s (lb/s)	431 (950)
Firing temperature, °C (°F)	>1,371 (>2,500)

[1]At International Standards Organization conditions firing natural gas. Performance information for syngas firing is not available.

Two gasification trains process a total of 5,567 tons of coal per day. A slurry (63 percent by weight coal) is transferred from the slurry storage tank to the gasifier with a 78/22 split to the primary and secondary stages. Oxygen (O_2) is produced in a cryogenic air separation unit. The coal slurry and oxygen react in the gasifier at about 4.2 MPa (615 psia) at a high temperature (averaging 1,371°C [>2,500°F]), while the portion of slurry injected into the second stage quenches the reaction by means of endothermic gasification reactions.

Gas leaving the gasifier is cooled in a fire-tube syngas cooler producing high-pressure steam. The cooled gas is cleaned of particulate matter (PM) via a cyclone collector followed by a ceramic candle filter. The raw syngas is then further cooled before being cleaned in a spray scrubber to remove remaining particulates and trace components. The syngas goes through a mercury (Hg) removal bed in which 95 percent of the Hg is removed from the syngas with activated carbon. Hydrogen sulfide (H_2S) is removed from the cool, particulate-free gas stream with a refrigerated promoted amine (methyldiethanolamine) solvent. Elemental sulfur is recovered in a Claus bypass-type sulfur recovery unit utilizing oxygen instead of air. The Claus plant produces molten sulfur by converting about one-third of the H_2S in the feed to sulfur dioxide (SO_2), then reacting the H_2S and SO_2 to produce sulfur and water.

A Brayton cycle, fueled by syngas, is used in conjunction with a conventional subcritical steam Rankine cycle for combined-cycle power generation. Compressed nitrogen from the air separation unit is used in syngas dilution, which aids in minimizing the formation of nitrogen oxides (NOx) during combustion in the gas turbine burner section. Two HRSGs and a steam turbine, operating at 12.4 MPa/566°C/566°C (1,800 psig/1,050°F/1,050°F), form the combined-cycle generation component of the plant. The two cycles are integrated by generation of steam in the HRSG, by feedwater heating in the HRSG, and by heat recovery from the IGCC process (syngas cooler). The plant produces a net output of 623 MWe. The summary of plant electrical generation performance is presented in Table 3. This configuration results in a net plant efficiency of 39.3 percent HHV, or a net plant HHV heat rate of 8,681 Btu/kWh.

Table 3. Plant Electrical Generation

	Electrical Summary
Advanced gas turbine x 2, MWe	464.0
HRSG steam turbine, MWe	278.5
Gross power output, MWe	742.5
Auxiliary power requirement, MWe	(119.1)
Net power output, MWe	623.4

Environmental Performance

The environmental specifications for a greenfield IGCC plant are based on the Electric Power Research Institute *CoalFleet User Design Basis for Coal-Based IGCC Plants* specification. Low SO_2 emissions (less than 4 ppmv in the flue gas) are achieved by capture of the sulfur in the Coastal SS Amine acid gas removal (AGR) process, which removes over 99 percent of the sulfur in the fuel gas to less than 30 ppmv. The resulting hydrogen sulfide-rich regeneration gas from the acid gas removal system is fed to a Claus plant, producing elemental sulfur. Nitrogen oxides emissions are limited by nitrogen dilution (primarily) and humidification (secondarily) to 15 ppmvd (as nitrogen dioxide at 15 percent O_2). Filterable PM discharge to the atmosphere is limited by a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. Ninety-five percent of the Hg is captured from the syngas by an activated carbon bed.

A summary of the resulting air emissions for the CoP IGCC plant is presented in Table 4.

Table 4. Air Emissions Summary @ 80% Capacity Factor

Pollutant	CoP IGCC Without CCS
CO_2	
• tons/year	3,777
• lb/MMBtu	199
• cost of CO_2 avoided ($/ton)	N/A
SO_2	
• tons/year	237
• lb/MMBtu	0.0125
NOx	
• tons/year	1,126
• lb/MMBtu	0.059
PM (filterable)	
• tons/year	135
• lb/MMBtu	0.0071
Hg	
• tons/year	0.011
• lb/TBtu	0.571

Cost Estimation

Plant size, primary/secondary fuel type, construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date were used to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant were based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 5.

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 13.3 percent of the CoP IGCC case TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 2.5 percent of the CoP IGCC case TPC and have been applied to the estimates as follows:

- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases.
- Mercury Removal – 5 percent on all IGCC cases.
- Combustion Turbine Generator – 5 percent on all IGCC cases without CCS.
- Instrumentation and Controls – 5 percent on all IGCC cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 80 percent for IGCC cases.

The 623 MWe (net) CoP IGCC plant was projected to have a TPC of $1,733/kWe, resulting in a 20-year LCOE of 75.3 mills/kWh.

Table 5. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions					
Case:	1x623 MWe net CoP IGCC				
Plant Size:	623.4	(MWe, net)	Heat Rate:	8,681	(Btu/kWh)
Primary/Secondary Fuel (type):	Illinois #6 Coal		Fuel Cost:	1.80	($/MMBtu)
Construction Duration:	3	(years)	Plant Life:	30	(years)
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)
Capacity Factor:	80	(%)	Capital Charge Factor:	17.5	(%)
Resulting Capital Investment (Levelized 2007 dollars)					**Mills/kWh**
Total Plant Cost					43.3
Resulting Operating Costs (Levelized 2007 dollars)[3]					**Mills/kWh**
Fixed Operating Cost					5.8
Variable Operating Cost					7.3
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu					**Mills/kWh**
					18.8
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					75.3

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

[3]No credit taken for by-product sales.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.

B_IG_CoP_051507

ConocoPhillips E-Gas™ IGCC Plant With Carbon Capture & Sequestration

Plant Overview

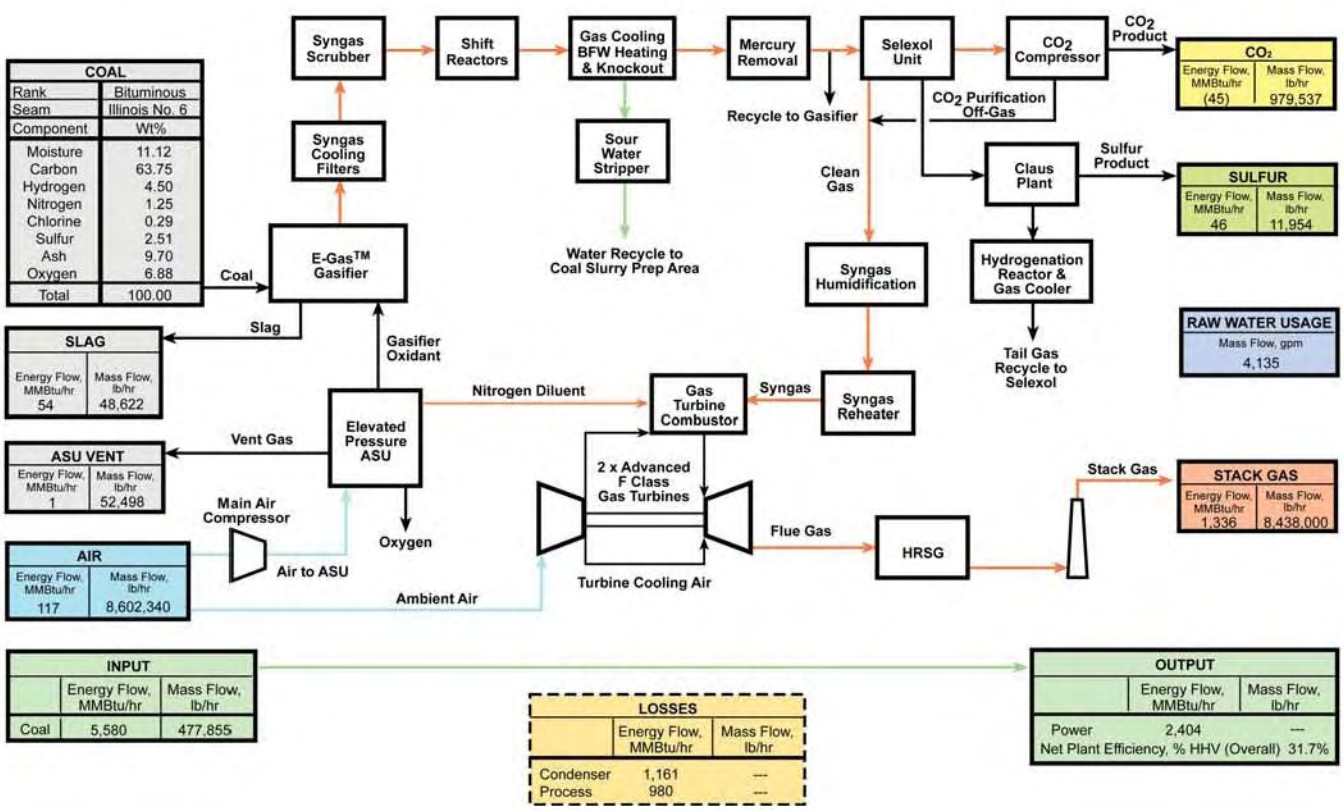
This analysis is based on a 518 MWe (net power output) Integrated Gasification Combined-Cycle (IGCC) plant, using ConocoPhillips E-Gas™ gasification technology, located at a greenfield site in the midwestern United States. The plant utilizes carbon capture and sequestration (CCS). Two pressurized entrained-flow, two-stage gasification trains feed two advanced F-Class combustion turbines. Water-gas-shift (WGS) reactors are used for sour gas shift. Two heat recovery steam generators (HRSGs) and one steam turbine provide additional power. Carbon dioxide (CO_2) is removed with the two-stage Selexol physical solvent process. The combination process and heat and mass balance diagram for the CoP IGCC plant with CCS is shown in Figure 1. The primary fuel is an Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb. The capacity factor (CF) for the plant is 80 percent without sparing of major train components. A summary of plant performance data for the CoP IGCC plant with CCS is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	CoP IGCC
Carbon capture	Yes
Net power output (kWe)	518,240
Net plant HHV efficiency (%)	31.7
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 80% capacity factor	105.7
Total plant cost ($ x 1,000)	$1,259,883
Cost of CO_2 avoided[1] ($/ton)	41

[1]The cost of CO_2 avoided is defined as the difference in the 20-year levelized cost-of-electricity between controlled and uncontrolled like cases divided by the difference in CO_2 emissions in kg/MWh.

Figure 1. Process Flow Diagram
CoP IGCC With CCS



Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

Table 2. Advanced Gas Turbine Performance[1]

	Advanced F-Class
Net output, MWe	185
Pressure ratio	18.5
Airflow, kg/s (lb/s)	431 (950)
Firing temperature, °C (°F)	>1,371 (>2,500)

[1]At International Standards Organization conditions firing natural gas. Performance information for syngas firing is not available.

The plant uses an improved version of the CoP gasification technology, which is currently in operation at the PSI Energy Inc. 265 MWe Wabash River IGCC plant near West Terre Haute, IN. All technology selected for the plant design is assumed to be available to facilitate a 2010 startup date for a newly constructed plant. However, because certain processes like the combustion turbine operating on a high-hydrogen content syngas and the two-stage Selexol process for CO_2 capture either have no commercial or limited commercial operating experience, a process contingency was included in those cost items. A summary of performance for the advanced F-Class combustion turbines for the CoP IGCC plant with CCS is presented in Table 2.

Two gasification trains process a total of 5,735 tons of coal per day. A slurry (63 percent by weight coal) is transferred from the slurry storage tank to the two-stage gasifier with a 78/22 split to the primary and secondary stages. Oxygen (O_2) is produced in a cryogenic air separation unit. The coal slurry and O_2 react in the gasifier at about 4.2 MPa (615 psia) at a high temperature (averaging 1,371°C [2,500°F]), while the portion of slurry injected into the second stage quenches the reaction by means of endothermic gasification reactions.

Gas leaving the gasifier is cooled in a fire-tube syngas cooler producing high-pressure steam. The cooled gas is cleaned of particulate matter (PM) via a cyclone collector followed by a ceramic candle filter. The raw syngas is then further cooled before being cleaned in a spray scrubber to remove remaining particulates and trace components. The syngas goes through a mercury (Hg) removal bed in which 95 percent of the Hg is removed from the syngas with activated carbon. Hydrogen sulfide (H_2S) is removed from the cool, particulate-free gas stream with a Selexol acid gas removal (AGR) system. Elemental sulfur is recovered in a Claus bypass-type sulfur recovery unit utilizing oxygen instead of air. The Claus plant produces molten sulfur by converting about one-third of the H_2S in the feed to sulfur dioxide (SO_2), then reacting the H_2S and SO_2 to produce sulfur and water.

To capture CO_2, a WGS reactor containing a series of three shifts with intercooled stages, converts a nominal 98 percent of the carbon monoxide to CO_2. Carbon dioxide is removed from the cool, particulate-free gas stream with Selexol solvent. The double-absorber Selexol process preferentially removes H_2S as a product stream, leaving CO_2 as a separate product stream. The CO_2 is dried and compressed to 15.3 MPa (2,215 psia) for subsequent pipeline transport. The compressed CO_2 is transported via pipeline to a geologic sequestration field for injection into a saline aquifer, which is located within 50 miles of the plant.

Table 3. Plant Electrical Generation

	Electrical Summary
Advanced gas turbine x 2, MWe	464.0
Steam turbine, MWe	229.8
Gross power output, MWe	693.8
Auxiliary power requirement, MWe	(175.6)
Net power output, MWe	518.2

A Brayton cycle, fueled by the syngas, is used in conjunction with a conventional subcritical steam Rankine cycle for combined-cycle power generation. Two HRSGs and a steam turbine, operating at 12.4 MPa/538°C/538°C (1,800 psig/1,000°F/1,000°F) form the combined-cycle generation component of the plant. The two cycles are integrated by generation of steam in the HRSGs, by feedwater heating in the HRSGs, and by heat recovery from the IGCC process (syngas cooler). The plant produces a net output of 518 MWe. The summary of plant electrical generation performance is presented in Table 3. This configuration results in a net plant efficiency of 31.7 percent HHV, or a net plant HHV heat rate of 10,757 Btu/kWh.

Environmental Performance

The environmental specifications for a greenfield IGCC plant are based on the Electric Power Research Institute *CoalFleet User Design Basis for Coal-Based IGCC Plants* specification. Low SO_2 emissions (less than 3 ppmv in the flue gas) are achieved by capture of the sulfur in the Selexol AGR process, which removes 99 percent of the sulfur in the fuel gas to less than 22 ppmv. The resulting H_2S-rich regeneration gas from the acid gas removal system is fed to a Claus plant, producing elemental sulfur. Nitrogen oxides (NOx) emissions are limited by nitrogen dilution (primarily) and syngas humidification (secondarily) to 15 ppmvd (as nitrogen dioxide at 15 percent O_2). Filterable PM discharge to the atmosphere is limited by a cyclone and a barrier filter in addition to the syngas scrubber and the gas-washing effect of the AGR absorber. Ninety-five percent of the Hg is captured from the syngas by an activated carbon bed. About eighty-eight percent of the CO_2 from the syngas is captured in the AGR system and compressed for shipment and sequestration.

A summary of the resulting air emissions for the CoP IGCC plant with CCS is presented in Table 4.

Table 4. Air Emissions Summary @ 80% Capacity Factor

Pollutant	CoP IGCC With CCS (90%)
CO_2	
• tons/year	460,175
• lb/MMBtu	23.6
• cost of CO_2 avoided ($/ton)	41
SO_2	
• tons/year	167
• lb/MMBtu	0.0085
NOx	
• tons/year	972
• lb/MMBtu	0.050
PM (filterable)	
• tons/year	139
• lb/MMBtu	0.0071
Hg	
• tons/year	0.011
• lb/TBtu	0.571

Cost Estimation

Plant size, primary/secondary fuel type, construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date were used to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant were based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 5.

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 13.7 percent of the CoP IGCC with CCS case TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 4.3 percent of the CoP IGCC with CCS case TPC and have been applied to the estimates as follows:

- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases.
- Two Stage Selexol – 20 percent on all IGCC CCS cases.
- Mercury Removal – 5 percent on all IGCC cases.
- Combustion Turbine Generator –10 percent on all IGCC cases with CCS.
- Instrumentation and Controls – 5 percent on all IGCC cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 80 percent for IGCC cases.

The calculated cost of transport, storage, and monitoring for CO_2 is $4.40/short ton, which adds 4.1 mills/kWh to the LCOE.

The 518 MWe (net) CoP IGCC plant with CCS was projected to have a TPC of $2,431/kWe, resulting in a 20-year LCOE of 105.7 mills/kWh.

Table 5. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions					
Case:	**1x518 MWe net CoP IGCC with CCS**				
Plant Size:	518.2	(MWe, net)	Heat Rate:	10,757	(Btu/kWh)
Primary/Secondary Fuel (type):	Illinois #6 Coal		Fuel Cost:	1.80	($/MMBtu)
Construction Duration:	3	(years)	Plant Life:	30	(years)
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)
Capacity Factor:	80	(%)	Capital Charge Factor:	17.5	(%)
Resulting Capital Investment (Levelized 2007 dollars)					**Mills/kWh**
Total Plant Cost					60.7
Resulting Operating Costs (Levelized 2007 dollars)[3]					**Mills/kWh**
Fixed Operating Cost					7.6
Variable Operating Cost					9.9
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu					**Mills/kWh**
					23.3
Resulting Levelized CO_2 Cost (2007 dollars)					**Mills/kWh**
					4.1
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					105.7

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

[3]No credit taken for by-product sales.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.

B_IG_CoP_CCS_051507

Shell IGCC Plant

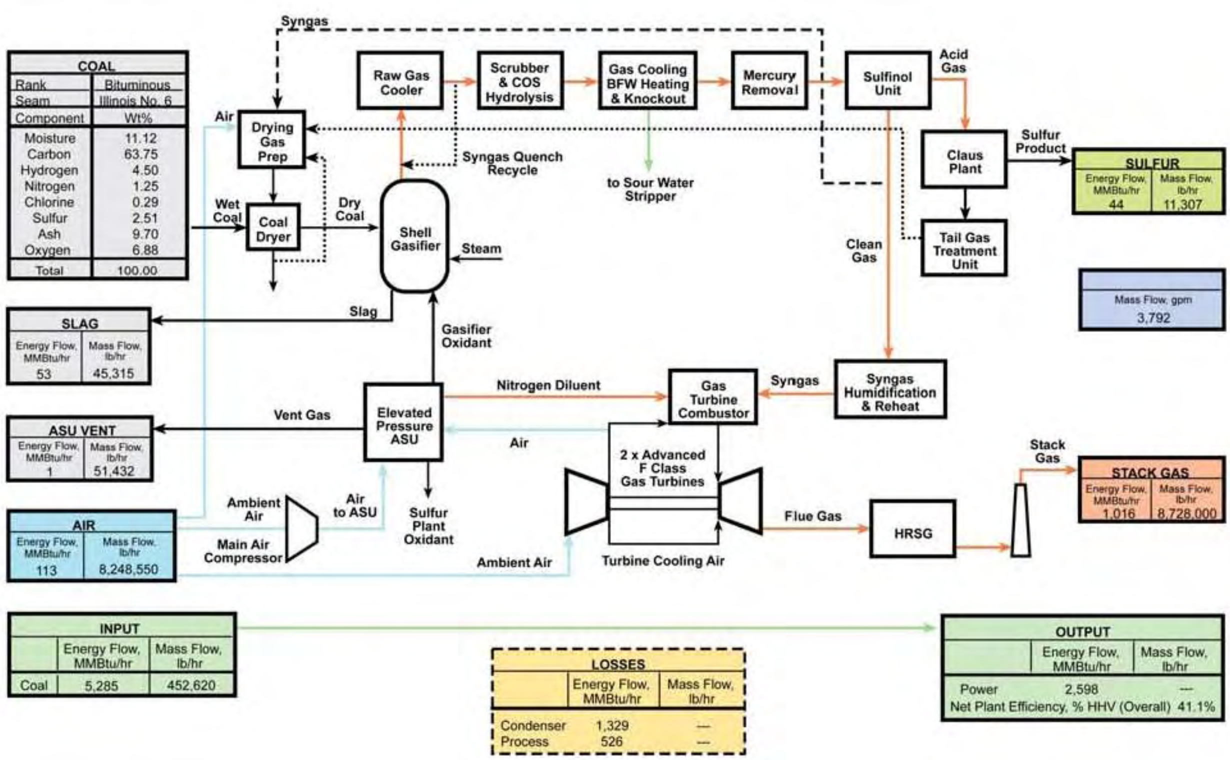
Plant Overview

This analysis is based on a 636 MWe (net power output) Integrated Gasification Combined-Cycle (IGCC) plant using Shell Global Solutions gasification technology located at a greenfield site in the midwestern United States. Two pressurized dry-feed entrained flow gasification trains feed two advanced F-Class combustion turbines. Two heat recovery steam generators (HRSGs) and one steam turbine provide additional power. The combination process and heat and mass balance diagram for the Shell IGCC plant is shown in Figure 1. The primary fuel is an Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb. The capacity factor (CF) for the plant is 80 percent without sparing of major train components. A summary of plant performance data for the Shell IGCC plant is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	Shell IGCC
Carbon capture	No
Net power output (kWe)	635,850
Net plant HHV efficiency (%)	41.1
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 80% capacity factor	80.5
Total plant cost ($ x 1,000)	$1,256,810

Figure 1. Process Flow Diagram
Shell IGCC



Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

Table 2. Advanced Gas Turbine Performance[1]

	Advanced F-Class
Net output, MWe	185
Pressure ratio	18.5
Airflow, kg/s (lb/s)	431 (950)
Firing temperature°C (°F)	>1,371 (>2,500)

[1] At International Standards Organization conditions firing natural gas. Performance information for syngas firing is not available.

The plant uses the Shell gasification technology. All technology selected in this plant design is assumed to be available to facilitate a 2010 startup date for a newly constructed plant. A summary of performance for the advanced F-Class combustion turbine for the Shell IGCC plant is presented in Table 2.

Two gasification trains process a total of 5,431 tons of coal per day. Dry coal is introduced to the gasifier via lockhoppers. Oxygen (O_2) is produced in a cryogenic air separation unit. The coal reacts with O_2 at about 1,427°C (2,600°F) to produce medium heating value syngas. The syngas is then quenched to around 891°C (1,635°F) by cooled recycled syngas. The syngas passes through a convective cooler and leaves at a temperature near 316°C (600°F). High-pressure saturated steam is generated in the syngas cooler and is joined with the main steam supply. The syngas passes through a cyclone and a raw gas candle filter where a majority of the fine particles are removed. The ash that is not carried out with the gas forms slag and runs down the interior walls, exiting the gasifier in liquid form.

The raw syngas then enters a scrubber for removal of chlorides and remaining particulate matter (PM). Following the scrubber, the raw syngas is reheated to 177°C (350°F) and fed to a Carbonyl Sulfide (COS) hydrolysis reactor where COS is catalytically converted to Hydrogen Sulfide (H_2S). The syngas is then cooled to about 35°C (95°F) before passing through a carbon bed to remove ninety five percent of the Hg. The Sulfinol process then removes essentially all of the CO_2 along with the H_2S and COS. Elemental sulfur is recovered in a Claus bypass-type sulfur recovery unit utilizing O_2 instead of air. The Claus plant produces molten sulfur by converting about one-third of the H_2S in the feed to sulfur dioxide (SO_2), then reacting the H_2S and SO_2 to produce sulfur and water.

A Brayton cycle fueled with syngas is used in conjunction with a conventional subcritical steam Rankine cycle. Nitrogen dilution (primarily), syngas humidification (secondarily) and steam injection to a lesser extent aid in minimizing formation of nitrogen oxides (NOx) during combustion in the gas turbine burner section. Two HRSGs and a steam turbine, operating at 12.4 MPa/566°C/566°C (1,800 psig/1,050°F/1,050°F), form the combined-cycle generation component of the plant. The two cycles are integrated by generation of steam in the HRSG, by feedwater heating in the HRSG, and by heat recovery from the IGCC process (convective syngas cooler). The plant produces a net output of 636 MWe. The summary of plant electrical generation performance is presented in Table 3. This configuration results in a net plant efficiency of 41.1 percent (HHV basis) or a net plant HHV heat rate of 8,304 Btu/kWh.

Table 3. Plant Electrical Generation

	Electrical Summary
Advanced gas turbine x 2, MWe	464.0
HRSG steam turbine, MWe	284.0
Gross power output, MWe	748.0
Auxiliary power requirement, MWe	(112.2)
Net power output, MWe	635.9

Environmental Performance

The environmental specifications for a greenfield IGCC plant are based on the Electric Power Research Institute *CoalFleet User Design Basis for Coal-Based IGCC Plants* specification. Low SO_2 emissions (less than 4 ppmv in the flue gas) are achieved by capture of the sulfur in the Sulfinol-M AGR process, which removes over 99 percent of the sulfur in the fuel gas. The resulting hydrogen sulfide-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. Nitrogen oxides emissions are limited by syngas humidification and nitrogen dilution in the gas turbine combustor to 15 ppmvd (as nitrogen oxides at 15 percent O_2). Filterable

PM discharge to the atmosphere is limited by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. Ninety-five percent of the Hg is captured from the syngas by an activated carbon bed.

A summary of the resulting air emissions for the Shell IGCC plant is presented in Table 4.

Table 4. Air Emissions Summary @ 80% Capacity Factor

Pollutant	Shell IGCC Without CCS
CO_2	
• tons/year	3,693,990
• lb/MMBtu	200
• cost of CO_2 avoided ($/ton)	N/A
SO_2	
• tons/year	230
• lb/MMBtu	0.0124
NOx	
• tons/year	1,082
• lb/MMBtu	0.058
PM (filterable)	
• tons/year	131
• lb/MMBtu	0.0071
Hg	
• tons/year	0.011
• lb/TBtu	0.571

Cost Estimation

Plant size, primary/secondary fuel type, construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date were used as inputs to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant were based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 5.

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 13.7 percent of the Shell IGCC case TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 2.6 percent of the Shell IGCC case TPC and have been applied to the estimates as follows:

- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases.
- Mercury Removal – 5 percent on all IGCC cases.
- Combustion Turbine Generator – 5 percent on all IGCC cases without CCS.
- Instrumentation and Controls – 5 percent on all IGCC cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 80 percent for IGCC cases.

The 636 MWe (net) Shell IGCC plant was projected to have a total capital requirement of $1,977/kWe, resulting in a 20-year LCOE of 80.5 mills/kWh.

Table 5. Major Financial Assumptions and Resulting Cost[1]

Major Assumptions					
Case:	**1x636 MWe net Shell IGCC**				
Plant Size:	635.9	(MWe, net)	Heat Rate:	8,304	(Btu/kWh)
Primary/Secondary Fuel (type):	Illinois #6 Coal		Fuel Cost:	1.80	($/MMBtu)
Construction Duration:	3	(years)	Plant Life:	30	(years)
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)
Capacity Factor:	80	(%)	Capital Charge Factor:	17.5	(%)
Resulting Capital Investment (Levelized 2007 dollars)					**Mills/kWh**
Total Plant Cost					49.4
Resulting Operating Costs (Levelized 2007 dollars)[3]					**Mills/kWh**
Fixed Operating Cost					5.8
Variable Operating Cost					7.3
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu					**Mills/kWh**
					18.0
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					80.5

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

[3]No credit taken for by-product sales.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.
B_IG_Shell_051507

Shell IGCC Plant With Carbon Capture & Sequestration

Plant Overview

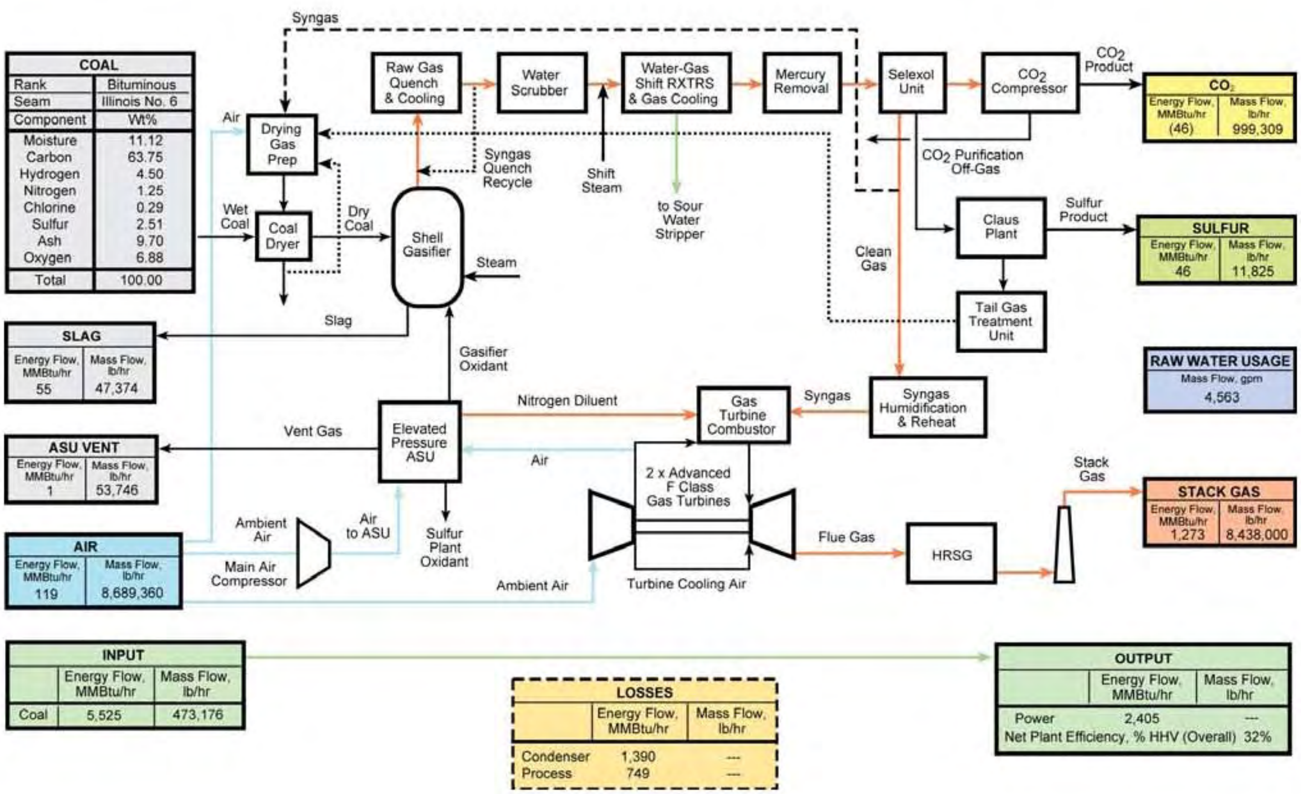
This analysis is based on a 517 MWe (net power output) Integrated Gasification Combined-Cycle (IGCC) plant using Shell Global Solutions gasification technology located at a greenfield site in the midwestern United States. The plant utilizes carbon capture and sequestration (CCS). Two pressurized, dry-feed, entrained–flow gasification trains feed two advanced F-Class combustion turbines. A quench reactor is utilized to provide a portion of the water required for the water gas shift. Two heat recovery steam generators (HRSGs) and one steam turbine provide additional power. Carbon dioxide (CO_2) is removed with the two-stage Selexol physical solvent process. The combination process and heat and mass balance diagram for the Shell IGCC plant with CCS is shown in Figure 1. The primary fuel is an Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb. The capacity factor (CF) for the plant is 80 percent without sparing of major train components. A summary of plant performance data for the Shell IGCC plant with CCS is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	Shell IGCC
Carbon capture	Yes
Gross power output (kWe)	517,135
Net plant HHV efficiency (%)	32.0
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 80% capacity factor	110.4
Total plant cost ($ x 1,000)	$1,379,524
Cost of CO_2 avoided[1] ($/ton)	42

[1] The cost of CO_2 avoided is defined as the difference in the 20-year levelized cost-of-electricity between controlled and uncontrolled like cases, divided by the difference in CO_2 emissions in kg/MWh.

Figure 1. Process Flow Diagram
Shell IGCC with CCS



Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

The plant uses the Shell gasification technology. All technology selected for the plant design is assumed to be available to facilitate a 2010 startup date for a newly constructed plant. However, because certain processes like the combustion turbine operating on a high-hydrogen content syngas and the two-stage Selexol process for CO_2 capture either have no commercial or limited commercial operating experience, a process contingency was included in this case. A summary of performance for the Advanced Gas Turbine for the Shell IGCC plant with CCS is presented in Table 2.

Table 2. Advanced Gas Turbine Performance[1]

	Advanced F-Class
Net output, MWe	185
Pressure ratio	18.5
Airflow, kg/s (lb/s)	431 (950)
Firing temperature, °C (°F)	>1,371 (>2,500)

[1]At International Standards Organization conditions firing natural gas. Performance information for syngas firing is not available.

Two gasification trains process a total of 5,678 tons of coal per day. Dry coal is introduced to the gasifier via lockhoppers. Oxygen (O_2) is produced in a cryogenic air separation unit. Coal, steam, and O_2 react in the gasifier at about 4.2 MPa (615 psia) at a temperature of 1,427°C (2,600°F) to produce syngas. The gas from the gasifier is quenched to 399°C (750°F) with water to provide a portion of the water required for water-gas-shift (WGS) reactions. The syngas passes through a cyclone and a raw gas candle filter where a majority of the fine particles are removed. The ash that is not carried out with the gas forms slag and runs down the interior walls, exiting the gasifier in liquid form.

The raw syngas is cooled to 260°C (500°F) and then enters a scrubber for removal of chlorides and remaining particulate matter (PM). Following the scrubber, the raw syngas is reheated to 285°C (545°F) and fed through two sour gas shift reactors for converting carbon monoxide (CO) to CO_2 and also hydrolyzing Carbonyl Sulfide (COS), eliminating the need for a separate COS hydrolysis reactor. The syngas is then cooled to about 35°C (95°F) before passing through a carbon bed to remove ninety-five percent of the Hg.

To capture CO_2, a WGS reactor containing a series of two shifts with inter-cooled stages, converts a nominal 96 percent of the CO to CO_2. Carbon dioxide is removed from the cool, particulate-free gas stream with Selexol solvent. The dual-absorber Selexol acid gas removal (AGR) process preferentially removes hydrogen sulfide (H_2S) as a product stream, leaving CO_2 as a separate product stream. Elemental sulfur is recovered in a Claus bypass-type sulfur recovery unit utilizing oxygen instead of air. The CO_2 is dried and compressed to 15.3 MPa (2,215 psia) for subsequent pipeline transport and sequestration. The compressed CO_2 is transported via pipeline to a geologic sequestration field for injection into a saline aquifer, which is located within 50 miles of the plant.

Table 3. Plant Electrical Generation

	Electrical Summary
Advanced gas turbine x 2, MWe	463.6
Steam turbine, MWe	229.9
Gross power output, MWe	693.5
Auxiliary power requirement, MWe	(176.4)
Net power output, MWe	517.1

A Brayton cycle, fueled by the syngas, is used in conjunction with a conventional subcritical steam Rankine cycle for combined cycle power generation. The two cycles are integrated by generation of steam in the HRSGs, by feedwater heating in the HRSGs, and by heat recovery from the IGCC process. The steam turbine operates at 12.4 MPa/538°C/538°C (1,800 psig/1,000 °F/1,000°F). The plant produces a net output of 517 MWe. The summary of plant electrical generation performance is presented in Table 3. This plant configuration results in a net plant efficiency of 32.0 percent HHV, or a net plant HHV heat rate of 10,674 Btu/kWh.

Environmental Performance

The environmental specifications for a greenfield IGCC plant are based on the Electric Power Research Institute *CoalFleet User Design Basis for Coal-Based IGCC Plants* specification. Low sulfur dioxide (SO_2) emissions (less than 3 ppmv in the flue gas) are achieved by capture of the sulfur in the two-stage Selexol acid gas removal (AGR) process, which removes over 99 percent of the sulfur in the fuel gas. The resulting H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. Nitrogen oxides (NOx) emissions are limited by nitrogen dilution (primarily) and syngas humidification (secondarily) in the gas turbine combustor to 15 ppmvd (as nitrogen oxide at 15 percent O_2). Filterable PM discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas-washing effect of the AGR absorber. Ninety-five percent of the Hg is captured from the syngas by an activated carbon bed. Approximately 90 percent of the CO_2 from the syngas is captured in the AGR system and compressed for pipeline transport and sequestration.

A summary of the resulting air emissions for the Shell IGCC plant with CCS is presented in Table 4.

Table 4. Air Emissions Summary @ 80% Capacity Factor

Pollutant	Shell IGCC with CCS (90%)
CO_2	
• tons/year	361,056
• lb/MMBtu	18.7
• cost of CO_2 avoided ($/ton)	42.0
SO_2	
• tons/year	204
• lb/MMBtu	0.0105
NOx	
• tons/year	944
• lb/MMBtu	0.049
PM (filterable)	
• tons/year	137
• lb/MMBtu	0.0071
Hg	
• tons/year	0.011
• lb/TBtu	0.571

Cost Estimation

Plant size, primary/secondary fuel type, construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date were used as inputs to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant were based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 5.

Project contingencies were added to the case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 14 percent of the Shell IGCC with CCS case TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 3.8 percent of the Shell IGCC with CCS case TPC and have been applied to the estimates as follows:

- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases.
- Two Stage Selexol – 20 percent on all IGCC CCS cases.
- Mercury Removal – 5 percent on all IGCC cases.
- Combustion Turbine Generator – 10 percent on all IGCC cases with CCS.
- Instrumentation and Controls – 5 percent on all IGCC cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 80 percent for IGCC cases.

The calculated cost of transport, storage, and monitoring for CO_2 is $4.30/short ton, which adds 4.1 mills/kWh to the LCOE.

The 517 (net) MWe Shell IGCC plant with CCS was projected to have a TPC of $2,668/kWe, resulting in a 20-year LCOE of 110.4 mills/kWh.

Table 5. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions					
Case:	1x517 MWe net Shell IGCC with CCS				
Plant Size:	517.1	(MWe, net)	Heat Rate:	10,674	(Btu/kWh)
Primary/Secondary Fuel (type):	Illinois #6 Coal		Fuel Cost:	1.80	($/MMBtu)
Construction Duration:	3	(years)	Plant Life:	30	(years)
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)
Capacity Factor:	80	(%)	Capital Charge Factor:	17.5	(%)
Resulting Capital Investment (Levelized 2007 dollars)					**Mills/kWh**
Total Plant Cost					66.6
Resulting Operating Costs (Levelized 2007 dollars)[3]					**Mills/kWh**
Fixed Operating Cost					7.2
Variable Operating Cost					9.3
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu					**Mills/kWh**
					23.2
Resulting Levelized CO_2 Cost (2007 dollars)					**Mills/kWh**
					4.1
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					110.4

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

[3]No credit taken for by-product sales.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.

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Pulverized Bituminous Coal Plants With and Without Carbon Capture & Sequestration

Technology Overview

Four pulverized coal (PC) Rankine cycle power plant configurations fired with bituminous coal were evaluated and the results are presented in this summary sheet. All cases were analyzed using a consistent set of assumptions and analytical tools. Each PC type was assessed with and without carbon capture and sequestration (CCS). The individual configurations are as follows:

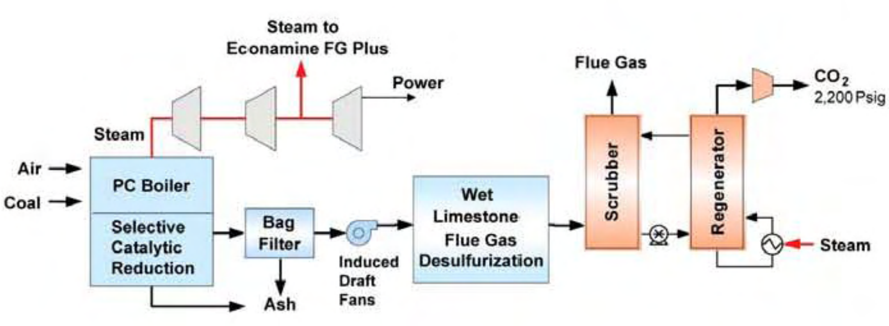
- Subcritical PC plant.
- Subcritical PC plant with CCS.
- Supercritical PC plant.
- Supercritical PC plant with CCS.

Each PC plant design is based on a market-ready technology that is assumed to be commercially available in time to support a 2010 startup date. The PC plants are built at a greenfield site in the midwestern United States and are assumed to operate at 85 percent capacity factor (CF) without sparing of major train components. Nominal plant size (gross rating) is 580 MWe without CCS and 670 MWe with CCS. All designs employ a one-on-one configuration comprising a state-of-the-art PC steam generator and a steam turbine. The primary fuel is Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb. The boiler is a dry-bottom, wall-fired unit that employs low-nitrogen oxides burners (LNBs) with over-fire air (OFA) and selective catalytic reduction (SCR) for nitrogen oxides (NOx) control, a wet-limestone forced-oxidation scrubber for sulfur dioxide (SO_2) and mercury (Hg) control, and a fabric filter for particulate matter (PM) control.

The PC cases are evaluated with and without CCS on a common 550 MWe net basis. The designs that include CCS are equipped with the Fluor Econamine Flue Gas (FG) Plus™ process. The CCS cases have a larger gross electrical output to compensate for the higher auxiliary loads. After compression to pipeline specification pressure, the carbon dioxide (CO_2) is assumed to be transported to a nearby underground storage facility for sequestration. The boiler and steam turbine industry ability to match unit size to a custom specification has been commercially demonstrated, enabling common net output comparison of the PC cases in this study.

See Figure 1 for a generic block flow diagram of a PC plant. The orange blocks in the figure represent the unit operations added to the configuration for CCS cases.

Figure 1. Pulverized Coal Power Plant



Orange blocks indicate unit operations added for CCS Case.

Particulate matter control: Baghouse achieves 0.013 lb/MMBtu (99.8% removal).

Sulfur oxides control: FGD to achieve 0.085 lb/MMBtu (98% removal).

Nitrogen oxides control: LNB + OFA + SCR to maintain 0.07 lb/MMBtu emissions limit.

Carbon dioxide control: Fluor Econamine FG Plus™ (90% removal).

Hg control: Co-benefit capture for ~90% removal.

Subcritical steam conditions: 2,400 psig/1,050°F/1,050°F.

Supercritical steam conditions: 3,500 psig/1100°F/1,100°F.

Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

Steam conditions for the Rankine cycle cases are based on input from the original boiler and steam turbine equipment manufacturers (OEMs) input on the most advanced steam conditions they would guarantee for a commercial project in the United States with PC units rated at nominal 550 MWe net capacity firing Illinois No. 6 coal. The input from the OEMs resulted in the following single-reheat steam conditions:

- For subcritical cases – 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F).
- For supercritical cases – 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F).

Recirculating evaporative cooling systems are used for cycle heat rejection. The average efficiency of the cases without CCS is almost 38 percent (HHV basis) for a plant with a nominal gross rating of 580 MWe.

The CCS cases require a significant amount of auxiliary power and extraction steam for the process, which reduces the output of the steam turbine. This requires a higher nominal gross plant output for the CCS cases of about 670 MWe for an average net plant efficiency of 26 percent (HHV basis).

The designs that include CCS are equipped with the Fluor Econamine FG Plus™ technology, which removes 90 percent of the CO_2 in the flue gas exiting the flue gas desulfurization (FGD) unit. Once captured, the CO_2 is dried and compressed to 15.3 MPa (2,215 psia). The compressed CO_2 is transported via pipeline to a geologic sequestration field for injection into a saline aquifer, which is located within 50 miles of the plant. Carbon dioxide transport, storage, and monitoring costs are included in the analyses.

Table 1. Fuel Analysis

Rank	Bituminous	
Seam	Illinois No. 6 (Herrin)	
Source	Old Ben Mine	
Proximate Analysis (weight %)[1]		
	As received	Dry
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile matter	34.99	39.37
Fixed carbon	44.19	49.72
Total	**100.00**	**100.00**
Sulfur	2.51	2.82
Higher heating value, Btu/lb	11,666	13,126
Lower heating value, Btu/lb	11,252	12,712

[1]The above proximate analysis assumes sulfur as a volatile matter.

Fuel Analysis and Costs

The design coal characteristics are presented in Table 1. All PC cases were modeled with Illinois No. 6 coal.

A cost of $1.80/MMBtu (January 2007 dollars) was determined from the Energy Information Administration AEO2007 for an eastern interior high-sulfur bituminous coal.

Environmental Design Basis

The environmental approach for this study was to evaluate each of the PC cases on the same regulatory design basis. The environmental specifications for a greenfield PC plant are based on Best Available Control Technology (BACT), which exceed New Source Performance Standard (NSPS) requirements. Table 2 provides details of the environmental design basis for PC plants built at a midwestern U.S. location. The emissions controls assumed for each of the four PC cases are as follows:

Table 2. Environmental Targets

Pollutant	PC[1]
SO_2	0.085 lb/MMBtu
NOx	0.07 lb/MMBtu
PM (filterable)	0.013 lb/MMBtu
Hg	1.14 lb/TBtu

[1]Based on BACT and NSPS.

- A wet-limestone FGD system was used for sulfur control and also provided co-benefit Hg removal.
- Low-NOx burners with OFA in conjunction with an SCR unit were used for NOx control.

- Fabric filter was used for PM control.
- Econamine FG Plus™ was used for CO_2 capture in the CCS cases.

Major Economic and Financial Assumptions

For the PC cases, capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates were developed for each plant based on adjusted vendor-furnished and actual cost data from recent design/build projects and resulted in determination of a revenue-requirement 20-year LCOE based on the power plant costs and assumed financing structure. Listed in Table 3 are the major economic and financial assumptions for the four PC cases.

Table 3. Major Economic and Financial Assumptions for PC Cases

Major Economic Assumptions	
Capacity factor	85%
Costs per year, constant U.S. dollars	2007 (January)
Illinois No. 6 delivered cost	$1.80/MMBtu
Construction duration	3 years
Plant startup date	2010 (January)
Major Financial Assumptions	
Depreciation	20 years
Federal income tax	34%
State income tax	6%
Low risk cases	
After-tax weighted cost of capital	8.79%
Capital structure:	
Common equity	50% (Cost = 12%)
Debt	50% (Cost = 9%)
Capital charge factor	16.4%
High risk cases	
After-tax weighted cost of capital	9.67%
Capital structure:	
Common equity	55% (Cost = 12%)
Debt	45% (Cost = 11%)
Capital charge factor	17.5%

Project contingencies were added to each of the cases to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was about 11 percent for the PC cases without CCS and roughly 12.5 percent for the PC cases with CCS.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies have been applied to the estimates as follows:

- CO_2 Removal System – 20 percent on all PC CCS cases.
- Instrumentation and Controls – 5 percent on the PC CCS cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 85 percent for PC cases.

For the PC cases that feature CCS, capital and operating costs were estimated for transporting CO_2 to an underground storage field, associated storage in a saline aquifer, and for monitoring beyond the expected life of the plant. These costs were then levelized over a 20-year period.

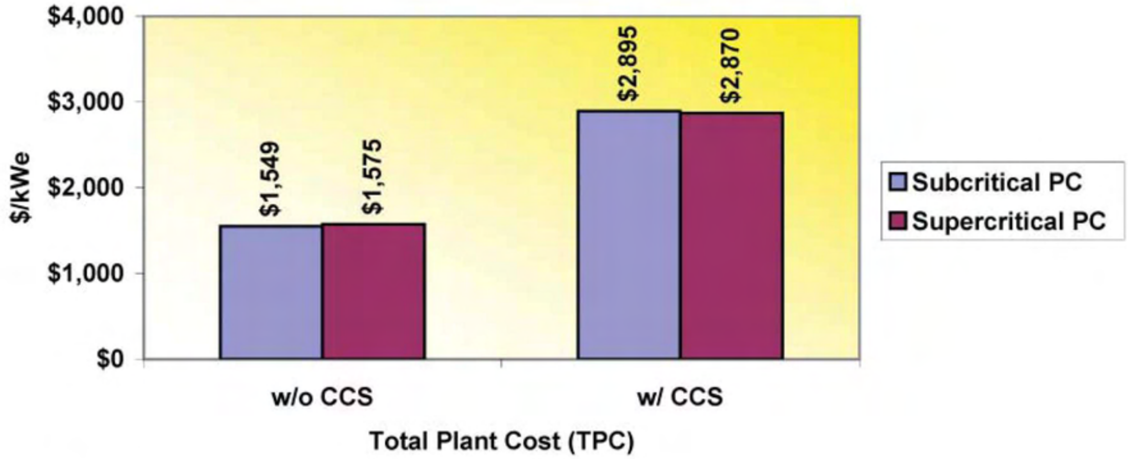
Results

An analysis of the four PC cases is presented in the following sections.

Capital Cost

The total plant cost (TPC) for each of the four PC cases is compared in Figure 2. The TPC includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

Figure 2. Comparison of TPC for the Four PC Cases



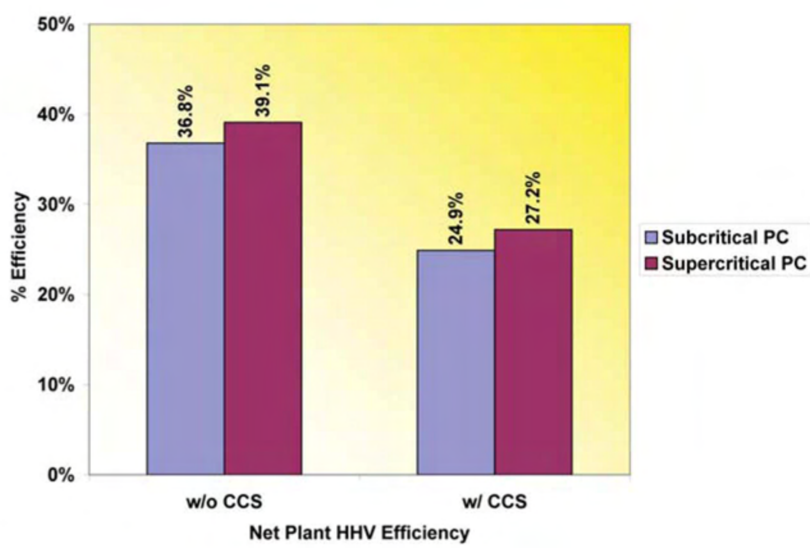
All costs are in January 2007 U.S. dollars.

The results of the analysis indicate that the supercritical PC cases and the subcritical PC cases are nearly the same capital cost. With CCS, the TPC increases by roughly 85 percent for both subcritical and supercritical cases, resulting in very similar capital costs of almost $2,900/kWe.

Efficiency

The net plant HHV efficiencies for the four PC cases are compared in Figure 3. This analysis indicates that the supercritical plant efficiency of 39.1 percent (HHV basis) is 2 percentage points higher than the subcritical case. With CCS, the efficiency penalty is a 12 percentage point drop in both subcritical and supercritical plants, resulting in an efficiency of about 25 percent (HHV basis) for the subcritical case, with the supercritical case being about 2 percentage points higher.

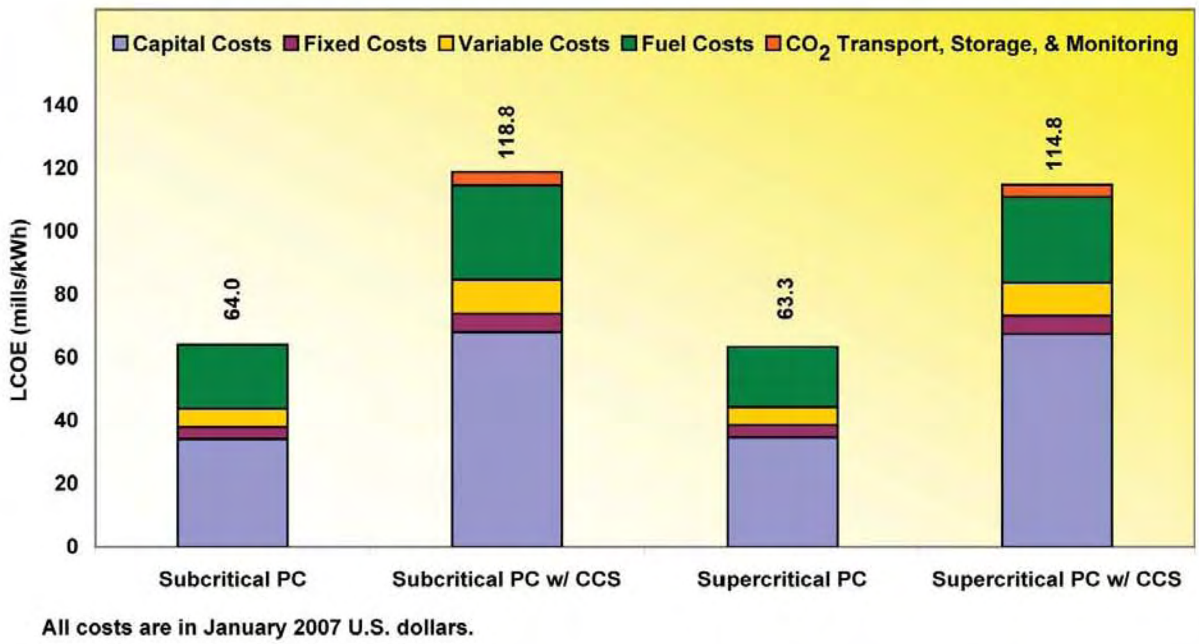
Figure 3. Comparison of Net Plant Efficiency for the Four PC Cases



Levelized Cost-of-Electricity

The LCOE is a measurement of the coal-to-busbar cost of power, and includes the TPC, fixed and variable operating costs, and fuel costs levelized over a 20-year period. The calculated cost of transport, storage, and monitoring for CO_2 is about $3.40/short ton, which adds roughly 4 mills to the LCOE.

Figure 4. Comparison of Levelized Cost-of-Electricity for the Four PC Cases



The PC plants generate power at an LCOE of about 64 mills/kWh at a CF of 85 percent. When CCS is included, the increased TPC and reduced efficiency result in a higher LCOE of roughly 117 mills/kWh.

Environmental Impacts

Table 4 provides a comparative summary of emissions from the four PC cases. Mass emission rates and cumulative annual totals are given for SO_2, NOx, PM, Hg, and CO_2. Additionally, plant water usage is shown.

The emissions from all four PC cases evaluated meet or exceed BACT and NSPS requirements. The CO_2 is reduced by 90 percent in the capture cases, resulting in emissions of less than 570,000 tons/year. The cost of CO_2 avoided is about $68/ton. The cost of CO_2 avoided is defined as the difference in the 20-year LCOE between controlled and uncontrolled like cases, divided by the difference in CO_2 emissions in kg/MWh. Raw water usage in the CCS cases is more than twice that of the cases without CCS primarily because of the large cooling water demand of the Econamine FG Plus™ process.

Table 4. Air Emissions Summary @ 85% Capacity Factor

	Pulverized Coal Boiler			
Pollutant	**PC Subcritical**		**PC Supercritical**	
	Without CCS	**With CCS (90%)**	**Without CCS**	**With CCS (90%)**
CO_2				
• tons/year	3,864,884	569,524	3,631,301	516,310
• lb/MMBtu	203	20.3	203	20.3
• cost of avoided CO_2 ($/ton)	—	68	—	68
SO_2				
• tons/year	1,613	Negligible	1,514	Negligible
• lb/MMBtu	0.0848	Negligible	0.0847	Negligible
NOx				
• tons/year	1,331	1,966	1,250	1,784
• lb/MMBtu	0.070	0.070	0.070	0.070
PM (filterable)				
• tons/year	247	365	232	331
• lb/MMBtu	0.0130	0.0130	0.0130	0.0130
Hg				
• tons/year	0.022	0.032	0.020	0.029
• lb/TBtu	1.14	1.14	1.14	1.14
Raw water usage, gpm	6,212	14,098	5,441	12,159

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.
B_PC_051507

Subcritical Pulverized Bituminous Coal Plant

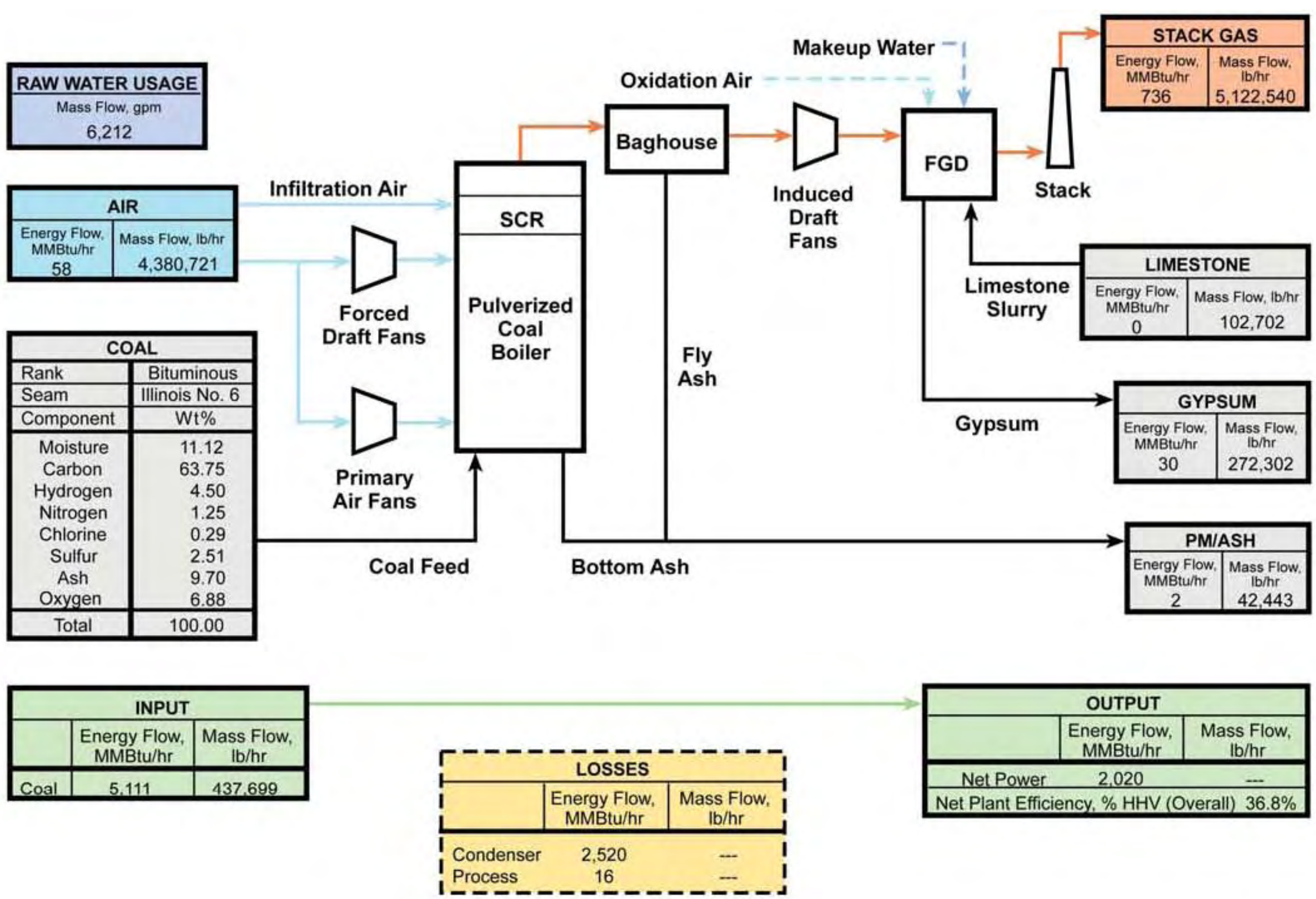
Plant Overview

This analysis is based on a 550 MWe (net power output) subcritical bituminous pulverized coal (PC) plant located at a greenfield site in the midwestern United States. This plant is designed to meet Best Available Control Technology (BACT) emission limits. The plant is a single-train design. The combination process, heat, and mass balance diagram for the subcritical PC plant is shown in Figure 1. The primary fuel is an Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb. The capacity factor (CF) for the plant is 85 percent without sparing of major train components. A summary of plant performance data for the subcritical PC plant is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	PC Subcritical
Carbon capture	No
Net power output (kWe)	550,445
Net plant HHV efficiency (%)	36.8%
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 85% capacity factor	64.0
Total plant cost ($ x 1,000)	$852,612

Figure 1. Process Flow Diagram
Subcritical Pulverized Coal Unit



Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

The analysis for the subcritical PC plant is based on a commercially available dry-bottom, wall-fired boiler equipped with low-nitrogen oxides burners (LNBs) and over-fire air (OFA). The unit is a balanced-draft, natural-circulation design equipped with a superheater, reheater, economizer, and air preheater. Hot flue gas exiting the boiler is treated by a selective catalytic reduction (SCR) unit for nitrogen oxides (NOx) removal, a baghouse for particulate matter (PM) removal, and a limestone-based scrubber for sulfur dioxide (SO_2) control and co-removal of mercury (Hg). This plant utilizes a conventional steam turbine for power generation. The Rankine cycle is based on a single reheat system with steam conditions of 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F).

Achieving a nominal 550 MWe net output with this plant configuration results in a HHV thermal input requirement of 1,496,479 kWt (5,106 MMBtu/hr basis). This thermal input is achieved by burning coal at a rate of 437,699 lb/hr, which yields an HHV net plant heat rate of 9,276 Btu/kWh (a net plant efficiency of 36.8 percent). The gross power output of 583 MWe is produced from the steam turbine generator. With an auxiliary power requirement of 33 MWe, the net plant output is 550 MWe.

Environmental Performance

This study assumes the use of BACT to meet the emission requirements of the 2006 New Source Performance Standards.

The subcritical PC plant emission control strategy consists of a wet-limestone, forced-oxidation scrubber that achieves a 98 percent removal of SO_2. The byproduct, calcium sulfate, is dewatered and stored onsite. The wallboard-grade material potentially can be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit is taken. The combination of SCR, a fabric filter and wet scrubber also provides co-benefit. Hg capture at an assumed 90 percent of the inlet value. The saturated flue gas exiting the scrubber is vented through the plant stack. NOx emissions are controlled through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86 percent. Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.8 percent.

A summary of the resulting air emissions is presented in Table 2.

Table 2. Air Emissions Summary @ 85% Capacity Factor

Pollutant	PC Subcritical Without CCS
CO_2	
• tons/year	3,864,884
• lb/MMBtu	203
• cost of CO_2 avoided ($/ton)	N/A
SO_2	
• tons/year	1,613
• lb/MMBtu	0.085
NOx	
• tons/year	1,331
• lb/MMBtu	0.070
PM	
• tons/year	247
• lb/MMBtu	0.013
Hg	
• tons/year	0.022
• lb/TBtu	1.14

Cost Estimation

Plant size, primary/secondary fuel type, construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date are used to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant are based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 3.

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 11.2 percent of the subcritical PC case without CCS TPC.

No process contingency is included in this case because all elements of the technology are commercially proven.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 85 percent for PC cases.

The 550 MWe (net) subcritical PC plant is projected to have a TPC of $1,549/kWe, resulting in a 20-year LCOE of 64.0 mills/kWh.

Table 3. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions					
Case:	**1x550 MWe net Subcritical PC**				
Plant Size:	550.4	(MWe, net)	Heat Rate:	9,276	(Btu/kWh)
Primary/Secondary Fuel (type):	Illinois #6 Coal		Fuel Cost:	1.80	($/MMBtu)
Construction Duration:	3	(years)	Plant Life:	30	(years)
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)
Capacity Factor:	85	(%)	Capital Charge Factor:	16.4	(%)
Resulting Capital Investment (Levelized 2007 dollars)					**Mills/kWh**
Total Plant Cost					34.1
Resulting Operating Costs (Levelized 2007 dollars)[3]					**Mills/kWh**
Fixed Operating Cost					3.8
Variable Operating Cost					5.8
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu					**Mills/kWh**
					20.2
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					64.0

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

[3]No credit taken for by-product sales.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.
B_PC_SUB_051507

Subcritical Pulverized Bituminous Coal Plant With Carbon Capture & Sequestration

Plant Overview

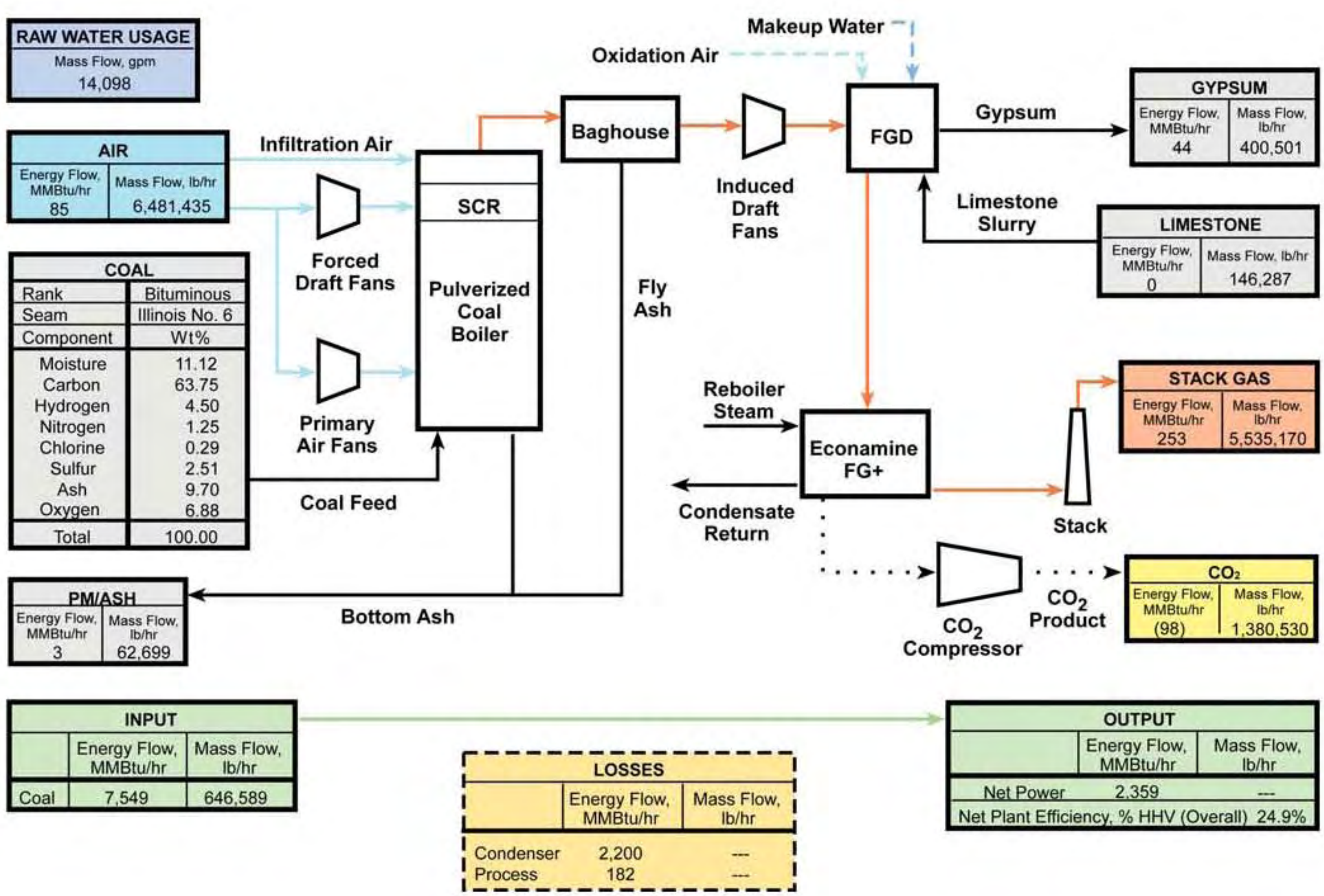
This analysis is based on a 550 MWe (net power output) subcritical bituminous pulverized coal (PC) plant located at a greenfield site in the midwestern United States. This plant captures carbon dioxide (CO_2) to be sequestered and is designed to meet Best Available Control Technology (BACT) emission limits. The plant is a single-train design. The combination process, heat, and mass balance diagram for the subcritical PC plant with carbon capture and sequestration (CCS) case is shown in Figure 1. The primary fuel is an Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb. The capacity factor (CF) for the plant is 85 percent without sparing of major train components. A summary of plant performance data for the subcritical PC plant with CCS is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	PC Subcritical
Carbon capture	Yes
Net power output (kWe)	549,613
Net plant HHV efficiency (%)	24.9
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 85% capacity factor	118.8
Total plant cost ($ x 1,000)	$1,591,277
Cost of CO_2 avoided[1] ($/ton)	68

[1]The cost of CO_2 avoided is defined as the difference in the 20-year levelized-cost-of electricity between controlled and uncontrolled like cases, divided by the difference in CO_2 emissions in kg/MWh.

Figure 1. Process Flow Diagram
Subcritical Pulverized Coal Unit With CCS



Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

The analysis for the subcritical PC plant with CCS is based on a commercially available dry-bottom, wall-fired boiler equipped with low-nitrogen oxides (NOx) burners (LNBs) and over-fire air (OFA). The unit is a balanced-draft, natural-circulation design equipped with a superheater, reheater, economizer, and air preheater. Hot flue gas (FG) exiting the boiler is treated by a selective catalytic reduction (SCR) unit for NOx removal, a baghouse for particulate matter (PM) removal, and a limestone-based scrubber for sulfur dioxide (SO_2) control and co-removal of mercury (Hg). This plant utilizes a conventional steam turbine for power generation. The Rankine cycle is based on a single reheat system with steam conditions of 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F).

This subcritical PC plant with CCS is equipped with the Fluor Econamine FG Plus™ technology for carbon capture. Flue gas exiting the scrubber system is directed to the Econamine FG Plus™ process, where CO_2 is absorbed in a monethanolamine-based solvent. A booster blower is required to overcome the process pressure drop. Carbon dioxide recovered in the Econamine FG Plus™ process is dried, compressed, and delivered to the plant fence line at 15.3 MPa (2,215 psia) for subsequent pipeline transport. The compressed CO_2 is transported via pipeline to a geologic sequestration field for injection into a saline aquifer, which is located within 50 miles of the plant.

Achieving a nominal 550 MWe net output with this plant configuration results in an HHV thermal input requirement of 2,210,668 kWt (7,543 MMBtu/hr basis). This thermal input is achieved by burning coal at a rate of 646,589 lb/hr, which yields an HHV net plant heat rate of 13,724 Btu/kWh (net plant efficiency of 24.9 percent). The gross power output of 680 MWe is produced from the steam turbine generator. With an auxiliary power requirement of 130 MWe, the net plant output is 550 MWe. The Econamine FG Plus™ process imposes a significant auxiliary power load on the system, which requires this case to have a higher gross output, as compared with the subcritical without CCS case, to maintain the same 550 MWe net output.

Environmental Performance

This study assumes the use of BACT to meet the emission requirements of the 2006 New Source Performance Standard for criteria pollutants.

The subcritical PC plant with CCS has an emission control strategy consisting of LNBs with OFA and SCR for NOx control, a pulse jet fabric filter for PM control, and a wet-limestone, forced-oxidation scrubber for SO_2 control. After NOx emissions are initially controlled through the use of LNBs and OFA, an SCR unit is used to further reduce the NOx concentration by 86 percent. Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.8 percent. The wet-limestone, forced-oxidation scrubber achieves a 98 percent removal of SO_2. A polishing scrubber included as part of the Econamine FG Plus™ process further reduces the SO_2 concentration to less than 10 ppmv. The balance of the SO_2 is removed in the Econamine absorber resulting in negligible SO_2 emissions. The byproduct from the wet-limestone scrubber calcium sulfate, is dewatered and stored onsite. The wallboard-grade material potentially can be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit is taken. The combination of SCR, a fabric filter and wet scrubber also

Table 2. Air Emissions Summary @ 85% Capacity Factor

Pollutant	PC Subcritical With CCS (90%)
CO_2	
• tons/year	569,524
• lb/MMBtu	20.3
• cost of CO_2 avoided ($/ton)	68
SO_2	
• tons/year	Negligible
• lb/MMBtu	Negligible
NOx	
• tons/year	1,966
• lb/MMBtu	0.070
PM	
• tons/year	365
• lb/MMBtu	0.013
Hg	
• tons/year	0.032
• lb/TBtu	1.14

provides co-benefit Hg capture at an assumed 90 percent of the inlet value. After leaving the Econamine FG Plus™ process, the flue gas is vented through the plant stack.

A summary of the resulting air emissions is presented in Table 2.

Cost Estimation

Plant size, primary/secondary fuel type, construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date were used as inputs to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant were based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 3.

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 12.5 percent of the subcritical PC CCS case TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 3.6 percent of the subcritical PC CCS case TPC and have been applied to the estimates as follows:

- CO_2 Removal System – 20 percent on all PC CCS cases.
- Instrumentation and Controls – 5 percent on the PC CCS cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 85 percent for PC cases.

For the PC cases that feature CCS, capital and operating costs were estimated for transporting CO_2 to an underground storage area, associated storage maintenance, and for monitoring beyond the expected life of the plant. These costs were then levelized over a 20-year period.

The calculated cost of transport, storage, and monitoring for CO_2 is $3.40/short ton, which adds 4.3 mills/kWh to the LCOE.

The 550 (net) MWe subcritical PC plant with CCS was projected to have a TPC of $2,888/kWe, resulting in a 20-year levelized COE of 118.8 mills/kWh.

Table 3. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions						
Case:	**1x550 MWe net Subcritical PC with CCS**					
Plant Size:	549.6	(MWe, net)	Heat Rate:	13,724	(Btu/kWh)	
Primary/Secondary Fuel (type):	Illinois #6 Coal		Fuel Cost:	1.80	($/MMBtu)	
Construction Duration:	3	(years)	Plant Life:	30	(years)	
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)	
Capacity Factor:	85	(%)	Capital Charge Factor:	17.5	(%)	
Resulting Capital Investment (Levelized 2007 dollars)						**Mills/kWh**
Total Plant Cost						68.0
Resulting Operating Costs (Levelized 2007 dollars)[3]						**Mills/kWh**
Fixed Operating Cost						5.8
Variable Operating Cost						10.8
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu						**Mills/kWh**
						29.8
Resulting Levelized CO_2 Cost (2007 dollars)						**Mills/kWh**
						4.3
Total Levelized Busbar Cost of Power (2007 dollars)						**Mills/kWh**
						118.8

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

[3]No credit taken for by-product sales.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.

B_PC_SUB_CCS_051507

Supercritical Pulverized Bituminous Coal Plant

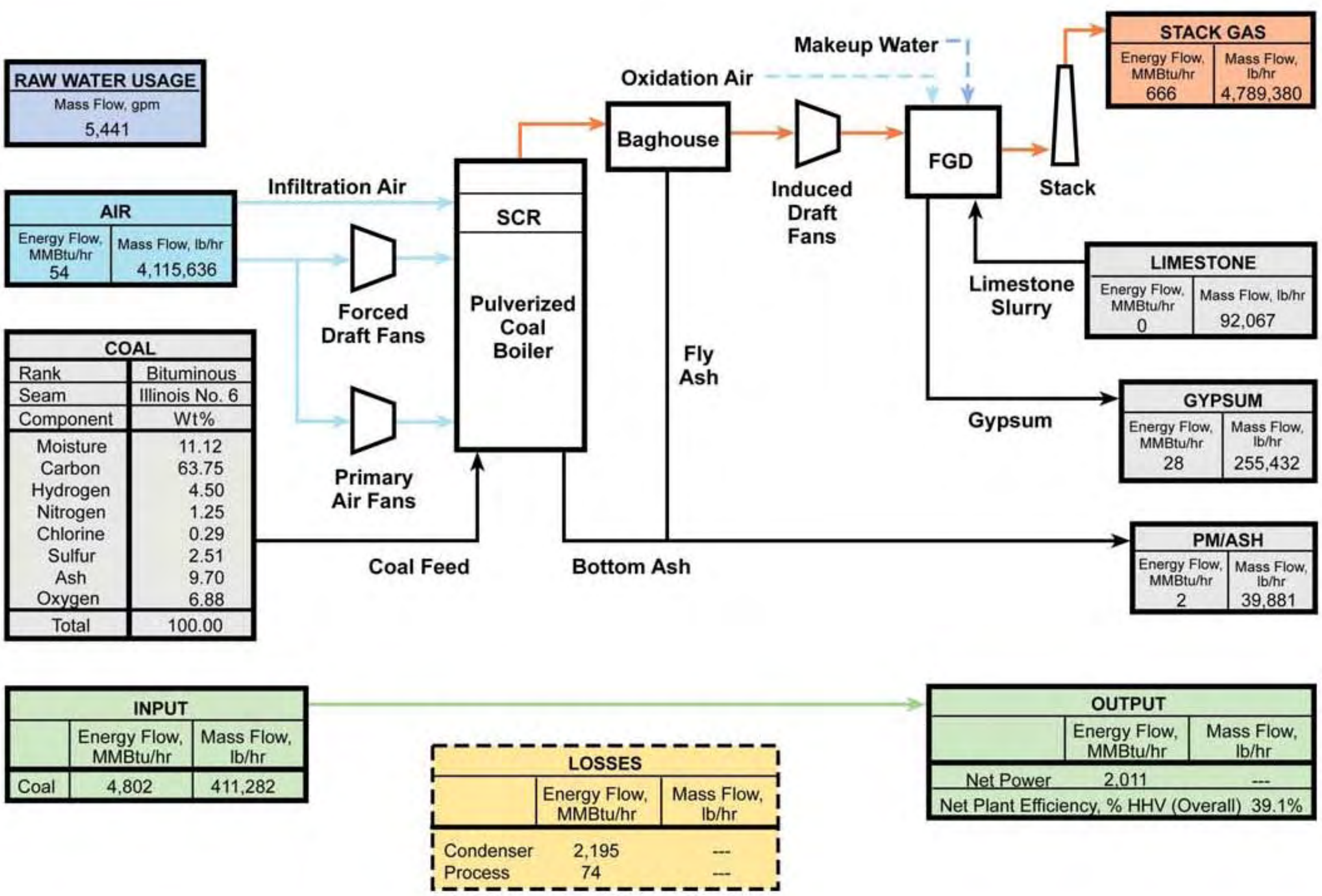
Plant Overview

This analysis is based on a 550 MWe (net power output) supercritical bituminous pulverized coal (PC) plant located at a greenfield site in the midwestern United States. This plant is designed to meet Best Available Control Technology (BACT) emission limits. The plant is a single-train design. The combination process, heat and mass balance diagram for the supercritical PC plant case is shown in Figure 1. The primary fuel is an Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb. The capacity factor (CF) for the plant is 85 percent without sparing of major train components. A summary of plant performance data for the supercritical PC plant is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	PC Supercritical
Carbon capture	No
Net power output (kWe)	550,150
Net plant HHV efficiency (%)	39.1
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 85% capacity factor	63.3
Total plant cost ($ x 1,000)	$866,391

Figure 1. Process Flow Diagram
Supercritical Pulverized Coal Unit



Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

The analysis for the supercritical PC plant is based on a commercially available supercritical dry-bottom, wall-fired boiler equipped with low-nitrogen oxides burners (LNBs) with over-fire air (OFA) and selective catalytic reduction (SCR). The unit is a balanced-draft, natural-circulation design equipped with a superheater, reheater, economizer, and air preheater. Hot flue gas exiting the boiler is treated by an SCR unit for nitrogen oxides (NOx) removal, a baghouse for particulate matter (PM) removal, and a wet limestone forced oxidation scrubber for sulfur dioxide (SO_2) control and co-removal of mercury (Hg). This plant utilizes a conventional steam turbine for power generation. The Rankine cycle is based on a single reheat system with steam conditions of 24.1 MPa/ 593°C/593°C (3,500 psig/1,100°F/1,100°F).

Achieving a nominal 550 MWe net output with this plant configuration results in a HHV thermal input requirement of 1,406,161 KWt (4,799 MMBtu/hr basis). This thermal input is achieved by burning coal at a rate of 411,282 lb/hr, which yields an HHV net plant heat rate of 8,721 Btu/kWh (net plant HHV efficiency of 39.1 percent). The gross power output of 580 MWe is produced from the steam turbine generator. With an auxiliary power requirement of 30 MWe, the net plant output is 550 MWe.

Environmental Performance

This study assumes the use of BACT to meet the emission requirements of the 2006 New Source Performance Standards.

The supercritical PC plant has an emission control strategy consisting of LNBs with OFA and SCR for NOx control, a pulse jet fabric filter for PM control, and a wet-limestone, forced-oxidation scrubber for SO_2 control. After NOx emissions are initially controlled through the use of LNBs and OFA, an SCR unit is used to further reduce the NOx concentration by 86 percent. Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.8 percent. The wet-limestone, forced-oxidation scrubber for SO_2 control achieves 98 percent removal efficiency. The byproduct, calcium sulfate, is dewatered and stored onsite. The wallboard-grade material can potentially be marketed and sold but, since it is highly dependent on local market conditions, no byproduct credit is taken. The combination of SCR, a fabric filter and wet scrubber also provides co-benefit Hg capture at an assumed 90 percent of the inlet value.

A summary of the resulting air emissions is presented in Table 2.

Table 2. Air Emissions Summary @ 85% Capacity Factor

Pollutant	PC Supercritical Without CCS
CO_2	
• tons/year	3,632,123
• lb/MMBtu	203
• cost of CO_2 avoided ($/ton)	N/A
SO_2	
• tons/year	1,514
• lb/MMBtu	0.085
NOx	
• tons/year	1,250
• lb/MMBtu	0.070
PM (filterable)	
• tons/year	232
• lb/MMBtu	0.013
Hg	
• tons/year	0.020
• lb/TBtu	1.14

Cost Estimation

Plant size, primary/secondary fuel type, construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date are used to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant are based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 3.

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 10.7 percent for the supercritical PC case TPC. No process contingency is included in this case because all elements of the technology are commercially proven.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 85 percent for PC cases.

The 550 MWe supercritical PC plant is projected to have a TPC of $1,574/kWe, resulting in a 20-year LCOE of 63.3 mills/kWh.

Table 3. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions					
Case:	**1x550 MWe net Supercritical PC**				
Plant Size:	550.2	(MWe, net)	Heat Rate:	8,721	(Btu/kWh)
Primary/Secondary Fuel (type):	Illinois #6 Coal		Fuel Cost:	1.80	($/MMBtu)
Construction Duration:	3	(years)	Plant Life:	30	(years)
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)
Capacity Factor:	85	(%)	Capital Charge Factor:	16.4	(%)
Resulting Capital Investment (Levelized 2007 dollars)					**Mills/kWh**
Total Plant Cost					34.7
Resulting Operating Costs (Levelized 2007 dollars)[3]					**Mills/kWh**
Fixed Operating Cost					3.9
Variable Operating Cost					5.7
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu					**Mills/kWh**
					19.0
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					63.3

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

[3]No credit taken for by-product sales.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.
B_PC_SUP_051507

Supercritical Pulverized Bituminous Coal Plant With Carbon Capture & Sequestration

Plant Overview

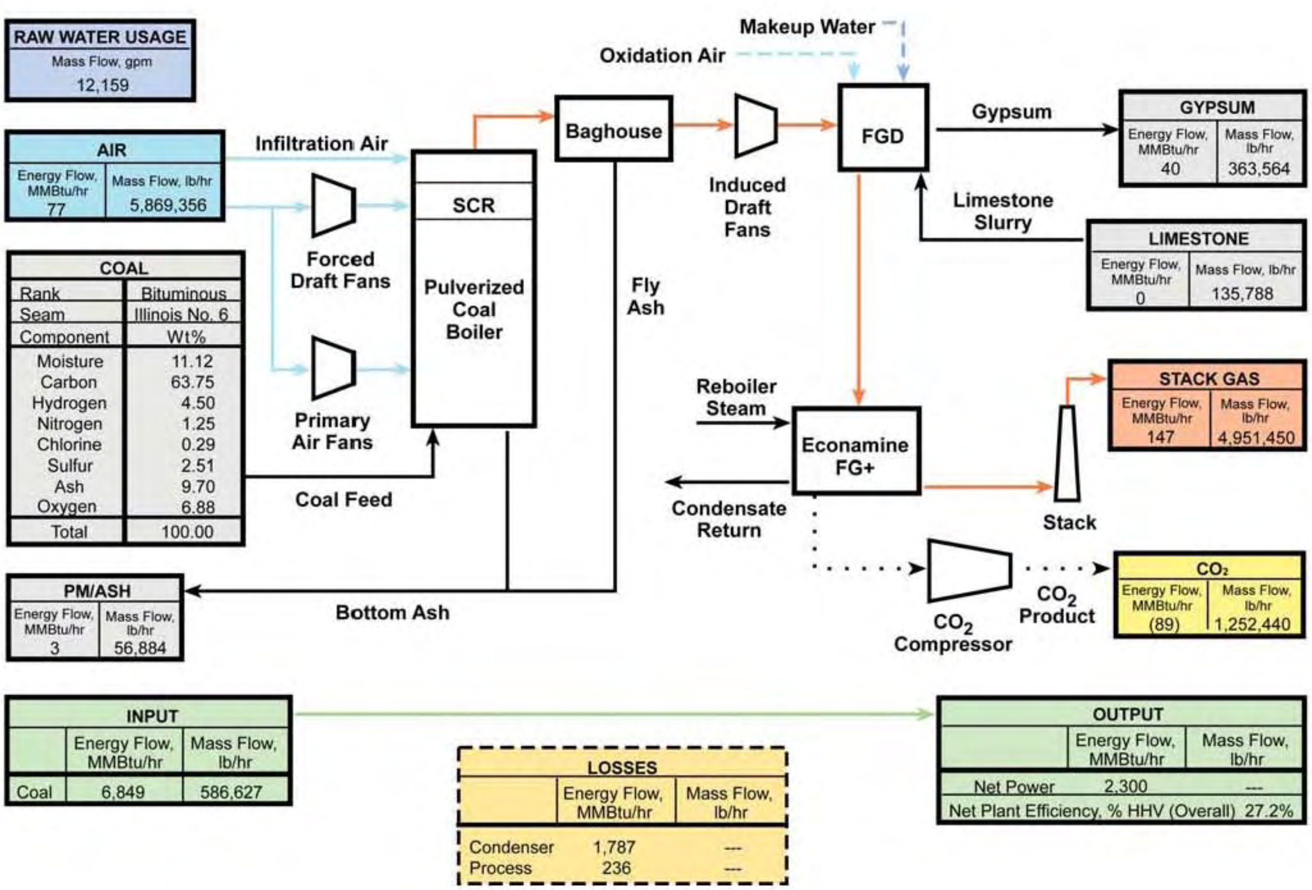
This analysis is based on a 550 MWe (net power output) supercritical bituminous pulverized coal (PC) plant located at a greenfield site in the midwestern United States. This plant captures carbon dioxide (CO_2) to be sequestered and is designed to meet Best Available Control Technology (BACT) emission limits. The plant is a single-train design. The combination process, heat, and mass balance diagram for the supercritical PC plant with carbon capture and sequestration (CCS) is shown in Figure 1. The primary fuel is an Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb. The capacity factor (CF) for the plant is 85 percent without sparing of major train components. A summary of plant performance data for the supercritical PC plant with CCS is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	PC Supercritical
Carbon capture	Yes
Net power output (kWe)	545,995
Net plant HHV efficiency (%)	27.2
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 85% capacity factor	114.8
Total plant cost ($ x 1,000)	$1,567,073
Cost of CO_2 avoided[1] ($/ton)	68

[1]The cost of CO_2 avoided is defined as the difference in the 20-year levelized cost-of-electricity between controlled and uncontrolled like cases, divided by the difference in CO_2 emissions in kg/MWh.

Figure 1. Process Flow Diagram
Supercritical Pulverized Coal Unit With CCS



Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

The analysis for the supercritical PC plant with CCS is based on a commercially available supercritical dry-bottom, wall-fired boiler equipped with low-nitrogen oxides (NOx) burners (LNBs), over-fire air (OFA), and selective catalytic reduction (SCR). The unit is a balanced-draft, natural-circulation design equipped with a superheater, reheater, economizer, and air preheater. Hot flue gas (FG) exiting the boiler is treated by an SCR unit for NOx removal, a baghouse for particulate matter (PM) removal, and a wet-limestone, forced-oxidation scrubber for sulfur dioxide (SO_2) control and co-removal of mercury (Hg). This plant utilizes a conventional steam turbine for power generation. The single reheat system uses a Rankine cycle with steam conditions of 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F).

This supercritical PC plant with CCS is equipped with the Fluor Econamine FG Plus™ technology for carbon capture. Flue gas exiting the scrubber system is directed to the Econamine FG Plus™ process, where CO_2 is absorbed in a monethanolamine-based solvent. A booster blower is required to overcome the process pressure drop. Carbon dioxide recovered in the Econamine FG Plus™ process is dried, compressed, and delivered to the plant fence line at 15.3 MPa (2,215 psia) for subsequent pipeline transport and sequestration. The compressed CO_2 is transported via pipeline to a geologic sequestration field for injection into a saline aquifer, which is located within 50 miles of the plant.

Achieving a nominal 550 MWe net output with this plant configuration, results in an HHV thermal input requirement of 2,005,660 kWt (6,845 MMBtu/hr). This thermal input is achieved by burning coal at a rate of 586,627 lb/hr, which yields an HHV net plant heat rate of 12,534 Btu/kWh (net plant HHV efficiency of 27.2 percent). The gross power output produced from the steam turbine generator is 663 MWe. With an auxiliary power requirement of 117 MWe, the net plant output is 546 MWe. The Econamine FG Plus™ process imposes a significant auxiliary power load on the system, which requires this case to have a higher gross output, as compared to the supercritical case without CCS, to maintain approximately the same net output.

Environmental Performance

This study assumes the use of BACT to meet the emission requirements of the 2006 New Source Performance Standard for criteria pollutants.

The supercritical PC plant with CCS has an emission control strategy consisting of LNBs with OFA and SCR for NOx control, a pulse jet fabric filter for PM control, and a wet-limestone, forced-oxidation scrubber for SO_2 control. After NOx emissions are initially controlled through the use of LNBs and OFA, an SCR unit is used to further reduce the NOx concentration by 86 percent. Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.8 percent. The wet-limestone, forced-oxidation scrubber achieves a 98 percent removal of SO_2. A polishing scrubber included as part of the Econamine FG Plus™ process further reduces the SO_2 concentration to less than 10 ppmv. The balance of the SO_2 is removed in the Econamine absorber resulting in negligible SO_2 emissions. The byproduct from the wet-limestone scrubber calcium sulfate, is dewatered and stored onsite. The wallboard-grade material potentially can be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit is taken. The combination of SCR,

Table 2. Air Emissions Summary @ 85% Capacity Factor

Pollutant	PC Supercritical With CCS (90%)
CO_2	
• tons/year	516,310
• lb/MMBtu	20.3
• cost of CO_2 avoided ($/ton)	68
SO_2	
• tons/year	Negligible
• lb/MMBtu	Negligible
NOx	
• tons/year	1,784
• lb/MMBtu	0.070
PM	
• tons/year	331
• lb/MMBtu	0.013
Hg	
• tons/year	0.029
• lb/TBtu	1.14

a fabric filter and wet scrubber also provides co-benefit Hg capture at an assumed 90 percent of the inlet value. The saturated FG exiting the scrubber is directed to the Econamine FG Plus™ process for CO_2 recovery. A booster blower is required to overcome the process pressure drop. After leaving the Econamine FG Plus™ process, the flue gas is vented through the plant stack.

A summary of the resulting air emissions is presented in Table 2.

Cost Estimation

Plant size, primary/secondary fuel type, construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date were used as inputs to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant were based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 3.

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 12.4 percent for the supercritical PC CCS case TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 3.5 percent of the supercritical PC CCS case TPC and have been applied to the estimates as follows:

- CO_2 Removal System – 20 percent on all PC CCS cases.
- Instrumentation and Controls – 5 percent on the PC CCS cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 85 percent for PC cases.

For the PC cases that feature CCS, capital and operating costs were estimated for transporting CO_2 to an underground storage area, associated storage maintenance, and for monitoring beyond the expected life of the plant. These costs were then levelized over a 20-year period.

The calculated cost of transport, storage, and monitoring for CO_2 is $3.40/short ton, which adds 3.9 mills/kWh to the LCOE.

The 550 (net) MWe supercritical PC plant with CCS was projected to have TPC of $2,868/kWe, resulting in a 20-year LCOE of 114.8 mills/kWh.

Table 3. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions						
Case:	**1x550 MWe net Supercritical PC with CCS**					
Plant Size:	545.9	(MWe, net)	Heat Rate:	12,534	(Btu/kWh)	
Primary/Secondary Fuel (type):	Illinois #6 Coal		Fuel Cost:	1.80	($/MMBtu)	
Construction Duration:	3	(years)	Plant Life:	30	(years)	
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)	
Capacity Factor:	85	(%)	Capital Charge Factor:	17.5	(%)	
Resulting Capital Investment (Levelized 2007 dollars)						**Mills/kWh**
Total Plant Cost						67.5
Resulting Operating Costs (Levelized 2007 dollars)[3]						**Mills/kWh**
Fixed Operating Cost						5.8
Variable Operating Cost						10.4
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu						**Mills/kWh**
						27.2
Resulting Levelized CO_2 Cost (2007 dollars)						**Mills/kWh**
						3.9
Total Levelized Busbar Cost of Power (2007 dollars)						**Mills/kWh**
						114.8

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

[3]No credit taken for by-product sales.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.

B_PC_SUP_CCS_051507

Natural Gas Combined-Cycle Plants With and Without Carbon Capture & Sequestration

Technology Overview

Two Natural Gas Combined-Cycle (NGCC) power plant configurations were evaluated, and the results are presented in this summary sheet. Both cases were analyzed using a consistent set of assumptions and analytical tools. The two configurations evaluated are based on an NGCC plant with and without carbon capture and sequestration (CCS).

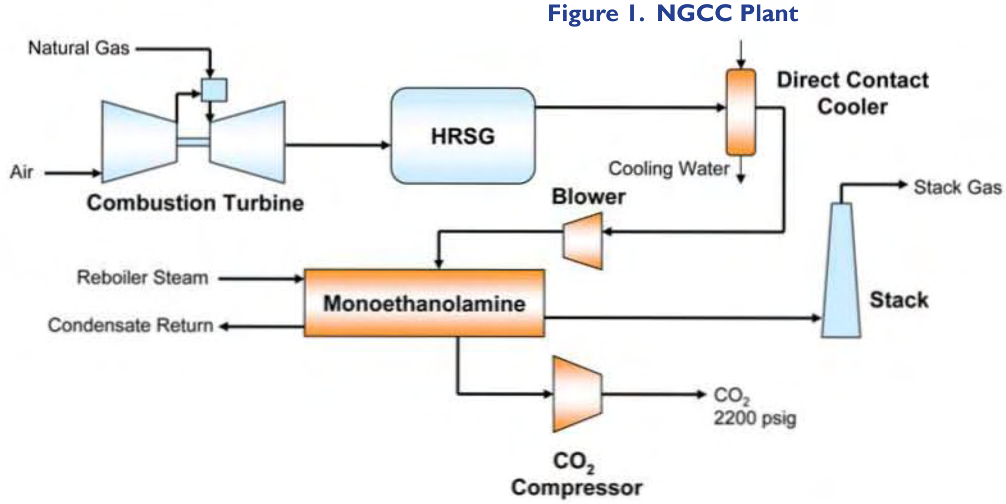
- NGCC plant utilizing Advanced F-Class combustion turbine generators (CTGs).
- NGCC plant utilizing Advanced F-Class CTGs with CCS.

Each NGCC plant design is based on a market-ready technology that is assumed to be commercially available in time to support a 2010 startup date. The NGCC plants are built at a greenfield site in the midwestern United States and are assumed to operate in baseload mode at 85 percent capacity factor (CF) without sparing of major train components. Nominal plant size (gross rating) is 570 MWe without CCS and 520 MWe with CCS. All designs consist of two advanced F-Class CTGs, two heat recovery steam generators (HRSGs), and one steam turbine generator in a multi-shaft 2x2x1 configuration.

The NGCC cases were evaluated with and without CCS on a common thermal input basis. The case that includes CCS is equipped with the Fluor Econamine (FG) Plus™ process. The NGCC with CCS case also has a smaller plant net output resulting from the additional CCS facility auxiliary loads and steam consumption. After compression to pipeline specification pressure, the carbon dioxide (CO_2) is assumed is to be transported to a nearby underground storage facility for sequestration.

The size of the NGCC designs was determined by the output of the commercially available combustion turbine. Therefore, evaluation of the NGCC designs on a common net output basis was not possible. For the cases with and without CCS, respective gross output was 520 and 570 MWe, and respective net output was 482 and 560 MWe. The natural gas (NG) flowrate was 165,182 lb/hr in both cases. See Figure 1 for a generic block flow diagram of an NGCC plant. The orange blocks in the figure represent the unit operations added to the configuration for CCS cases.

Figure 1. NGCC Plant



Nitrogen oxides control: dry low-NOx burner + selective catalytic reduction to maintain 2.5 ppmvd @ 15% oxygen

Carbon dioxide control: Monoethanolamine system for 90% removal

Steam conditions: 2,400 psig/1,050°F/950°F

Orange blocks indicate unit operations added for CCS case.

Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

The combined-cycle plant was based on two CTGs. The CTG is representative of the advanced F-Class CTGs with an International Standards Organization base rating of 184,400 kWe (when firing NG). This machine is an axial flow, single-shaft, constant-speed unit, with variable inlet guide vanes and Multi-Nozzle Quiet Combustor dry low-NOx (DLN) burner combustion system. Additionally, a selective catalytic reduction (SCR) system further reduces the nitrogen oxides (NOx) emissions. The Rankine cycle portion of both designs uses a single-reheat 16.5 MPa/566°C/510°C (2,400 psig/1,050°F/950°F) cycle. Recirculating evaporative cooling systems are used for cycle heat rejection. The efficiency of the case without CCS is almost 51 percent, with a gross rating of 570 MWe.

The CCS case requires a significant amount of auxiliary power and extraction steam for the process, which reduces the output of the steam turbine. This results in a lower net plant output for the CCS cases of about 482 MWe for an average net plant efficiency of almost 44 percent higher heating value (HHV).

The CCS case is equipped with the Fluor Econamine Flue Gas (FG) Plus™ technology, which removes 90 percent of the CO_2 in the FG exiting the HRSG unit. Once captured, the CO_2 is dried and compressed to 15.3 MPa (2,215 psia). The compressed CO_2 is transported via pipeline to a geologic sequestration field for injection into a saline formation, which is located within 50 miles of the plant. Therefore, CO_2 transport, storage, and monitoring costs are included in the analyses.

Table 1. Fuel Analysis

Natural Gas		
Component		**Volume Percentage**
Methane	CH_4	93.9
Ethane	C_2H_6	3.2
Propane	C_3H_8	0.7
n-Butane	C_4H_{10}	0.4
Carbon dioxide	CO_2	1.0
Nitrogen	N_2	0.8
Total		**100.0**
	LHV	**HHV**
kJ/kg	47,764	52,970
kJ/scm	35	39
Btu/lb	20,552	22,792
Btu/scf	939	1,040

Fuel Analysis and Costs

The design NG characteristics are presented in Table 1. Both NGCC cases were modeled with the design NG.

A NG cost of $6.40/MMkJ ($6.75/MMBtu) (January 2007 dollars) was determined from the Energy Information Administration AEO2007 for an eastern interior high-sulfur bituminous coal.

Environmental Design Basis

The environmental design for this study was based on evaluating both of the NGCC cases using the same regulatory design basis. The environmental specifications for a greenfield NGCC plant are based on the pipeline-quality NG specification in Table 1 and EPA 40 CFR Part 60, Subpart KKKK. Table 2 provides details of the environmental design basis for NGCC plants built at a midwestern U.S. location. The emissions controls assumed for each of the two NGCC cases are as follows:

- Dry low-NOx burners in conjunction with SCR for NOx control in both cases.
- Econamine process for CO_2 capture in the CCS case.

Table 2. Environmental Targets

Pollutant	NGCC
SO_2	Negligible
NOx	2.5 ppmvd @ 15% Oxygen
PM (filterable)	Negligible
Hg	N/A

NGCC plants produce negligible amounts of SO_2, particulate matter (PM), and mercury (Hg); therefore, no emissions controls equipment or features are required for these pollutants.

Major Economic and Financial Assumptions

For the NGCC cases, capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates were developed for each plant based on adjusted vendor-furnished and actual cost data from recent design/build projects and resulted in determination of a revenue-requirement 20-year LCOE based on the power plant costs and assumed financing structure. Listed in Table 3 are the major economic and financial assumptions for the two NGCC cases.

Project contingencies were added to each of the cases to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 10.6 percent for the NGCC case without CCS TPC and roughly 13.3 percent for the NGCC case with CCS.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies have been applied to the estimates as follows:

- CO_2 Removal System – 20 percent on all NGCC CCS cases.
- Instrumentation and Controls – 5 percent on the NGCC CCS cases.

Table 3. Major Economic and Financial Assumptions for NGCC Cases

Major Economic Assumptions	
Capacity factor	85%
Costs year in constant U.S. dollars	2007 (January)
Natural gas delivered cost	$6.75/MMBtu
Construction duration	3 Years
Plant startup date	2010 (January)
Major Financial Assumptions	
Depreciation	20 years
Federal income tax	34%
State income tax	6%
Low risk cases	
After-tax weighted cost of capital	8.79%
Capital structure:	
Common equity	50% (Cost = 12%)
Debt	50% (Cost = 9%)
Capital charge factor	16.4%
High risk cases	
After-tax weighted cost of capital	9.67%
Capital structure:	
Common equity	55% (Cost = 12%)
Debt	45% (Cost = 11%)
Capital charge factor	17.5%

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 85 percent for NGCC cases.

For the NGCC case that features CCS, capital and operating costs were estimated for transporting CO_2 to an underground storage field, associated storage in a saline aquifer, and for monitoring beyond the expected life of the plant. These costs were then levelized over a 20-year period.

Results

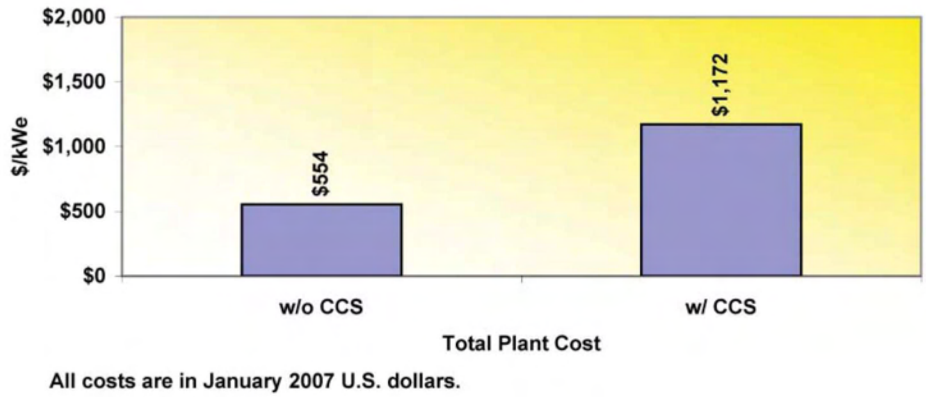
The results of the analysis of the two NGCC cases are presented in the following subsections.

Capital Cost

The total plant cost (TPC) for each of the two NGCC cases is compared in Figure 2. The TPC includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

The results of the analysis indicate that an NGCC costs $554/kWe, and that an additional $618/kWe is needed for the NGCC plant with CCS.

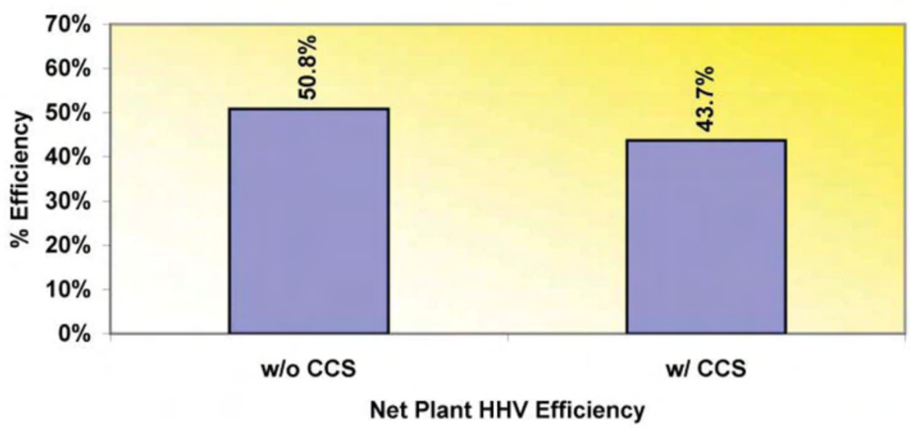
Figure 2. Comparison of TPC for the Two NGCC Cases



Efficiency

The net plant HHV efficiencies for the two NGCC cases are compared in Figure 3. This analysis indicates that adding CCS to the NGCC reduces plant HHV efficiency by more than 7 percentage points, from 50.8 percent to 43.7 percent.

Figure 3. Comparison of Net Plant Efficiency for the Two NGCC Cases



Levelized Cost-of-Electricity

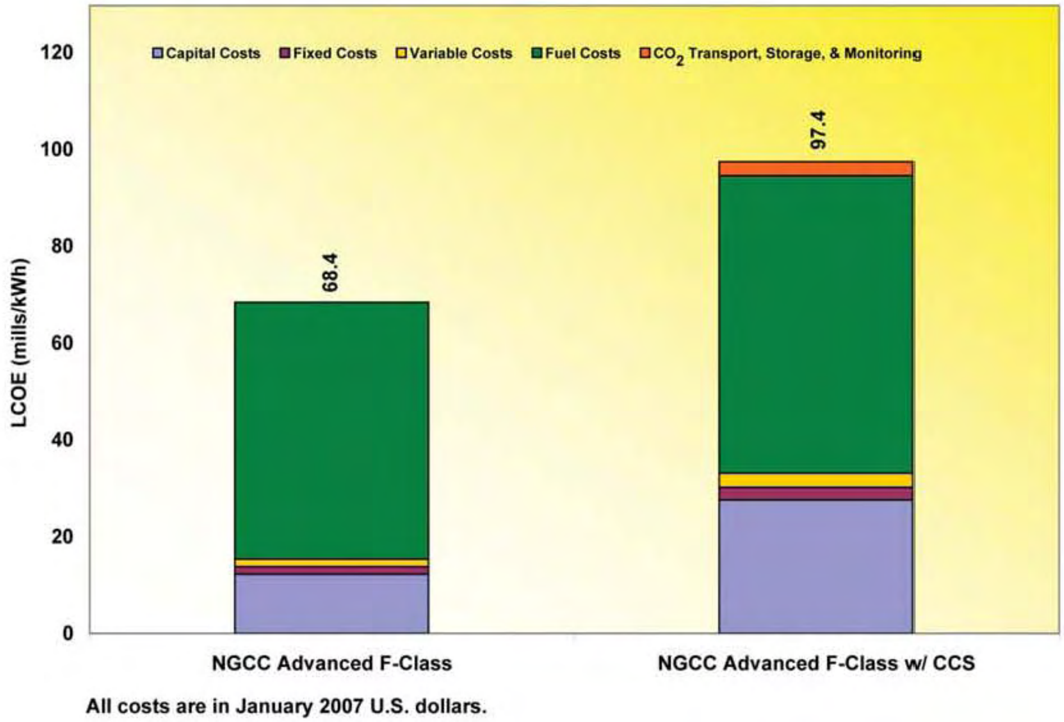
The LCOE is a measurement of the coal-to-busbar cost of power, and includes the TPC, fixed and variable operating costs, and fuel costs levelized over a 20-year period. The calculated cost of transport, storage, and monitoring for CO_2 is about $7.00/short ton, which adds roughly 3 mills to the LCOE.

The NGCC without CCS plant generates power at an LCOE of 68.4 mills/kWh at a CF of 85 percent. When CCS is included, the increased TPC and reduced efficiency result in a higher LCOE of 97.4 mills/kWh.

Environmental Impacts

Listed in Table 4 is a comparative summary of emissions from the two NGCC cases. Mass emission rates and cumulative annual totals are given for sulfur dioxide (SO_2), NOx, PM, Hg, and CO_2.

Figure 4. Comparison of Levelized Cost-of-Electricity for the Two NGCC Cases



The emissions from both NGCC plants evaluated meet or exceed Best Available Control Technologies requirements for the design NG specification and EPA 40 CFR Part 60, Subpart KKKK. The CO_2 is reduced by 90 percent in the capture case, resulting in less than 167,000 tons/year of CO_2 emissions. The cost of CO_2 avoided is defined as the difference in the 20-year LCOE between controlled and uncontrolled like cases, divided by the difference in CO_2 emissions in kg/MWh. In this analysis, the cost of CO_2 avoided is about \$83/ton. Sulfur dioxide, Hg, and PM emissions are negligible. Raw water usage in the CCS case is over 85 percent greater than for the case without CCS primarily because of the large Econamine process cooling water demand.

Table 4. Comparative Emissions for the Two NGCC Cases @ 85% Capacity Factor

Plant Type	NGCC Without CCS	NGCC With CCS (90%)
CO_2		
• tons/year	1,661,720	166,172
• lb/MMBtu	119	11.9
• cost of avoided CO_2 (\$/ton)	N/A	83
SO_2		
• tons/year	N/A	N/A
• lb/10^6 Btu	N/A	N/A
NOx		
• tons/year	127	127
• lb/MMBtu	0.009	0.009
PM (filterable)		
• tons/year	N/A	N/A
• lb/MMBtu	N/A	N/A
Hg		
• tons/year	N/A	N/A
• lb/TBtu	N/A	N/A
Raw water usage, gpm	2,511	4,681

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.
B_NG_051507

Natural Gas Combined-Cycle Plant

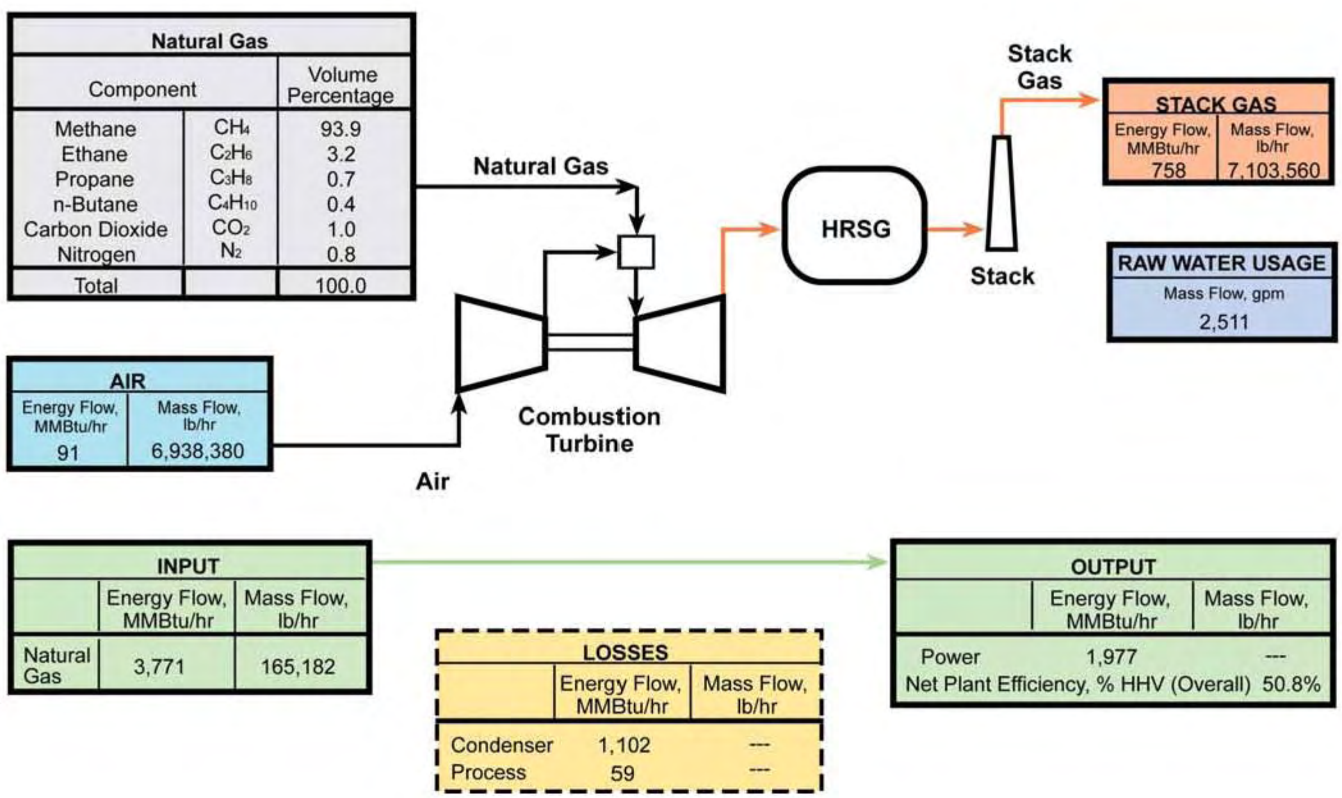
Plant Overview

This analysis is based on a 560 MWe (net power output) natural gas combined-cycle (NGCC) plant located at a greenfield site in the midwestern United States. This plant is designed to meet Best Available Control Technology (BACT) emission limits. The combination process, heat, and mass balance diagram for the NGCC plant is shown in Figure 1. The primary fuel is natural gas (NG) with a higher heating value (HHV) of 22,792 Btu/lb. The plant is assumed to operate in baseload mode at a capacity factor (CF) of 85 percent without sparing of major train components. A summary of plant performance data for the NGCC plant is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	NGCC
Carbon capture	No
Net power output (kWe)	560,360
Net plant HHV efficiency (%)	50.8
Primary fuel (type)	Natural Gas
Levelized cost-of-electricity (mills/kWh) @ 85% capacity factor	68.4
Total plant cost ($ x 1,000)	$310,710

Figure 1. Process Flow Diagram
NGCC



Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

Table 2. Advanced Gas Turbine Performance[1]

	Advanced F-Class
Net output, MWe	185
Pressure ratio	18.5
Airflow, kg/s (lb/s)	431 (950)
Firing temperature, °C (°F)	>1,371 (>2,500)

[1]At International Standards Organization conditions firing natural gas.

The analysis for the NGCC plant is based on two advanced F-Class combustion turbine generators (CTGs), which are assumed to be commercially available to support startup in 2010; two heat recovery steam generators (HRSGs); and one steam turbine generator (STG) in a multi-shaft 2x2x1 configuration with a recirculating wet cooling tower for cycle heat rejection. A performance summary for the advanced F-Class CTGs is presented in Table 2. The unit consists of an NG system that feeds NG at the required pressure and temperature to the two axial flow, constant-speed CTGs with variable inlet guide vanes, and a dry low-NOx (DLN) burner combustion system. Each CTG exhausts to an HRSG configured with high-, intermediate-, and low-pressure steam systems, including drum, superheater, reheater, and economizer sections. Steam from both HRSGs flows to a conventional steam turbine for power generation. The Rankine cycle consists of a single reheat system with steam conditions of 16.5 MPa/566°C/510°C (2,400 psig/1,050°F/950°F). Nitrogen oxides (NOx) emissions are controlled to 25 ppmvd (referenced to 15 percent oxygen (O_2)) by the DLN combustion system and then further reduced by a selective catalytic reduction (SCR) system. The SCR system was designed for 90 percent reduction of NOx. These together achieve the emission limit of 2.5 ppmvd NOx (referenced to 15 percent O_2). All other support systems and equipment are typical for a conventional NGCC plant. Plant performance is based on the properties of pipeline-quality NG.

Table 3. Plant Electrical Generation

	Electrical Summary
Advanced gas turbine x 2, MWe	370.2
Steam turbine, MWe	200.0
Gross power output, MWe	570.2
Auxiliary power requirement, MWe	(9.8)
Net power output, MWe	560.4

Achieving a nominal 560 MWe net output with such a plant configuration results in an HHV thermal input requirement of 1,103,362 kWt (3,765 MMBtu/hr basis). This thermal input is achieved by burning NG at a rate of 165,182 lb/hr, which yields an HHV net plant heat rate of 6,719 Btu/kWh (HHV efficiency of 50.8 percent). The gross power output of 570 MWe is produced from the advanced CTGs and the STG. With an auxiliary power requirement of 10 MWe, the net plant output is 560 MWe. The summary of plant electrical generation performance is presented in Table 3.

Environmental Performance

This study assumes the use of BACT to meet the emission requirements of the 2006 New Source Performance Standards.

NGCC plants use NG as their fuel, which creates negligible emissions of sulfur dioxide (SO_2), particulate matter (PM), and mercury (Hg); therefore, NGCC plants require no emissions controls equipment or features to reduce these emissions. NOx emissions are controlled to 25 ppmvd (referenced to 15 percent O_2) by the DLN combustion system and then further reduced by an SCR system. The SCR system was designed for 90 percent reduction while firing NG. The DLN burner, together with the SCR, achieves the emission limit of 2.5 ppmvd (referenced to 15 percent O_2).

A summary of the resulting air emissions is presented in Table 4.

Cost Estimation

Plant size, primary/secondary fuel type, construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date were used as inputs to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant were based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 5.

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 10.6 percent of the TPC.

No process contingency is included in this case because all elements of the technology are commercially proven.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 85 percent for NGCC cases.

Table 4. Air Emissions Summary @ 85% Capacity Factor

Pollutant	NGCC Without CCS
CO_2	
• tons/year	1,661,720
• lb/MMBtu	119
• cost of CO_2 avoided ($/ton)	N/A
SO_2	
• tons/year	Negligible
• lb/MMBtu	Negligible
NOx	
• tons/year	127
• lb/MMBtu	0.009
PM (filterable)	
• tons/year	Negligible
• lb/MMBtu	Negligible
Hg	
• tons/year	Negligible
• lb/TBtu	Negligible

The 560 (net) MWe NGCC plant was projected to have a TPC of $554/kWe, resulting in a 20-year LCOE of 68.4 mills/kWh.

Table 5. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions					
Case:	1x560 MWe net NGCC				
Plant Size:	560.4	(MWe, net)	Heat Rate:	6,719	(Btu/kWh)
Primary/Secondary Fuel (type):	Natural Gas		Fuel Cost:	1.80	($/MMBtu)
Construction Duration:	3	(years)	Plant Life:	30	(years)
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)
Capacity Factor:	85	(%)	Capital Charge Factor:	16.4	(%)
Resulting Capital Investment (Levelized 2007 dollars)					**Mills/kWh**
Total Plant Cost					12.2
Resulting Operating Costs (Levelized 2007 dollars)					**Mills/kWh**
Fixed Operating Cost					1.5
Variable Operating Cost					1.5
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu					**Mills/kWh**
					53.1
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					68.4

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.
B_NGCC_FClass_051507

Natural Gas Combined-Cycle Plant With Carbon Capture & Sequestration

Plant Overview

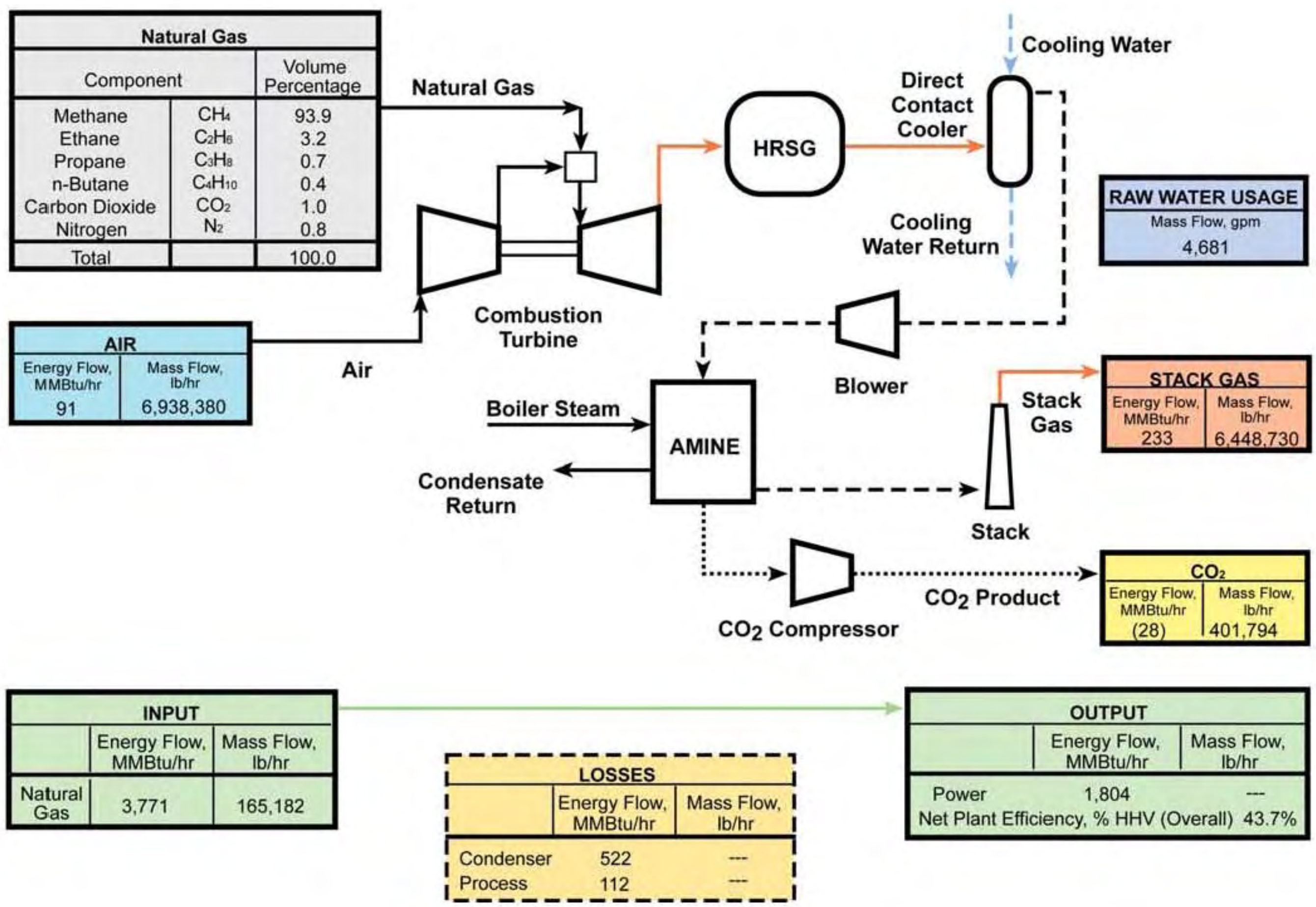
This analysis is based on a 482 MWe (net power output) natural gas combined-cycle (NGCC) plant located at a greenfield site in the midwestern United States. This plant captures carbon dioxide (CO_2) to be sequestered and is designed to meet Best Available Control Technology (BACT) emission limits. The combination process, heat, and mass balance diagram for the NGCC plant with carbon capture and sequestration (CCS) is shown in Figure 1. The primary fuel is natural gas (NG) with a higher heating value (HHV) of 22,792 Btu/lb. The plant is assumed to operate in baseload mode at a capacity factor (CF) of 85 percent without sparing for major train components. A summary of plant performance data for the NGCC plant with CCS case is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	NGCC
Carbon capture	Yes
Net power output (kWe)	481,890
Net plant HHV efficiency (%)	43.7
Primary fuel (type)	Natural gas
Levelized cost-of-electricity (mills/kWh) @ 85% capacity factor	97.4
Total plant cost ($ x 1,000)	$564,628
Cost of CO_2 avoided[1] ($/ton)	83

[1]The cost of CO_2 avoided is defined as the difference in the 20-year levelized cost-of-electricity between controlled and uncontrolled like cases, divided by the difference in CO_2 emissions in kg/MWh.

Figure 1. Process Flow Diagram NGCC With CCS



Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

The analysis for the NGCC plant with CCS is based on two advanced F-Class combustion turbine generators (CTGs) that are assumed to be commercially available to support startup in 2010, two heat recovery steam generators (HRSGs), and one steam turbine generator (STG) in a multi-shaft 2x2x1 configuration with a recirculating wet cooling tower for cycle heat rejection. A performance summary for the advanced CTG for the NGCC plant with CCS is presented in Table 2. The unit consists of an NG system that feeds NG at the required pressure and temperature to the two axial-flow, constant-speed CTGs with variable inlet guide vanes and a dry low-NOx (DLN) burner combustion system. Each CTG exhausts to an HRSG configured with high-, intermediate-, and low-pressure steam systems, including drum, superheater, reheater, and economizer sections. Steam flows from both HRSGs to a conventional STG for power generation. The Rankine cycle consists of a single reheat system with steam conditions of 16.5 MPa/566°C/510°C (2,400 psig/1,050°F/950°F). Nitrogen oxides emissions are controlled to 25 ppmvd (referenced to 15 percent oxygen (O_2) by the DLN combustion system and then further reduced by a selective catalytic reduction (SCR) system. The SCR system was designed for 90 percent nitrogen oxides (NOx) reduction. The DLN burner, together with the SCR system, achieves the emission limit of 2.5 ppmvd (referenced to 15 percent O_2). All other support systems and equipment are typical for a conventional NGCC plant. Plant performance is based on the properties of pipeline-quality NG.

Table 2. Advanced Gas Turbine Performance[1]

	Advanced F-Class
Net output, MWe	185
Pressure ratio	18.5
Airflow, kg/s (lb/s)	431 (950)
Firing temperature, °C (°F)	>1,371 (>2,500)

[1]At International Standards Organization conditions firing natural gas.

Flue gas (FG) exiting the HRSGs is directed to the Fluor Econamine FG Plus™ process, where CO_2 is absorbed in a monoethanolamine-based solvent. A booster blower is required to overcome the process pressure drop. Carbon dioxide removed in the Econamine FG Plus™ process is dried and compressed for subsequent pipeline transport and sequestration. The CO_2 is delivered to the plant fence line at 15.3 MPa (2,215 psia). The compressed CO_2 is transported via pipeline to a geologic sequestration field for injection into a saline aquifer, which is located within 50 miles of the plant.

Achieving a nominal 482 MWe net output with the above plant configuration results in an HHV thermal input requirement of 1,103,363 kWt (3,766 MMBtu/hr basis). This thermal input is achieved by burning NG at a rate of 165,182 lb/hr, which yields an HHV net plant heat rate of 7,813 Btu/kWh (HHV efficiency of 43.7 percent). The gross power output of 520 MWe is produced from the advanced CTGs and the STG. With an auxiliary power requirement of 38 MWe, the net plant output is 482 MWe. The summary of plant electrical generation performance is presented in Table 3.

Table 3. Plant Electrical Generation

	Electrical Summary
Advanced gas turbine x 2, MWe	370.2
Steam turbine, MWe	149.9
Gross power output, MWe	520.1
Auxiliary power requirement, MWe	(38.2)
Net power output, MWe	481.9

Environmental Performance

This study assumes the use of BACT to meet the emission requirements of the 2006 New Source Performance Standards.

NGCC plants use NG as their fuel, which creates negligible emissions of sulfur dioxide (SO_2), particulate matter (PM), and mercury (Hg); therefore, NGCC plants require no emissions control equipment or features to reduce these emissions. Nitrogen oxides emissions are controlled to 25 ppmvd (referenced to 15 percent O_2) by the DLN combustion system and then further reduced by an SCR system. The SCR system was designed for

90 percent NOx reduction while firing NG. The low NOx burner, together with the SCR, achieves the emission limit of 2.5 ppmvd (referenced to 15 percent O_2).

CO_2 capture is designed to recover 90 percent of the CO_2 in the FG stream by the Econamine FG Plus™ process.

A summary of the resulting air emissions is presented in Table 4.

Table 4. Air Emissions Summary @ 85% Capacity Factor

Pollutant	NGCC With CCS
CO_2	
• tons/year	166,172
• lb/MMBtu	11.9
• cost of CO_2 avoided ($/ton)	83
SO_2	
• tons/year	Negligible
• lb/MMBtu	Negligible
NOx	
• tons/year	127
• lb/MMBtu	0.009
PM (filterable)	
• tons/year	Negligible
• lb/MMBtu	Negligible
Hg	
• tons/year	Negligible
• lb/TBtu	Negligible

Cost Estimation

Plant size, primary/secondary fuel type, construction time total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date were used as inputs to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant were based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 5.

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 13.3 percent of the TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 5 percent of the NGCC CCS case TPC and have been applied to the estimates as follows:

- CO_2 Removal System – 20 percent on all NGCC CCS cases.
- Instrumentation and Controls – 5 percent on the NGCC CCS cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 85 percent for NGCC cases. The assumed CF for NGCC cases is 85 percent.

For the NGCC cases that feature CCS, capital and operating costs were estimated for transporting CO_2 to an underground storage area, associated storage maintenance, and for monitoring beyond the expected life of the plant. These costs were then levelized over a 20-year period.

The calculated cost of transport, storage, and monitoring for CO_2 is $7.00/short ton, which adds 2.9 mills/kWh to the LCOE.

The 482 (net) MWe NGCC plant with CCS was projected to have a TPC of $1,172/kWe, resulting in a 20-year LCOE of 97.4 mills/kWh.

Table 5. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions					
Case:	1x482 MWe net NGCC with CCS				
Plant Size:	481.9	(MWe, net)	Heat Rate:	7,813	(Btu/kWh)
Primary/Secondary Fuel (type):	Natural Gas		Fuel Cost:	1.80	($/MMBtu)
Construction Duration:	3	(years)	Plant Life:	30	(years)
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)
Capacity Factor:	85	(%)	Capital Charge Factor:	17.5	(%)
Resulting Capital Investment (Levelized 2007 dollars)					**Mills/kWh**
Total Plant Cost					27.5
Resulting Operating Costs (Levelized 2007 dollars)					**Mills/kWh**
Fixed Operating Cost					2.6
Variable Operating Cost					3.0
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu					**Mills/kWh**
					61.4
Resulting Levelized CO_2 Cost (2007 dollars)					**Mills/kWh**
					2.9
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					97.4

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.
B_NGCC_FClass_CCS_051507

Advanced Coal Cost and Emissions Update

Ronald L. Schoff
Project Manager – Advanced Coal
(rschoff@epri.com)

Mega Symposium
Baltimore, MD
August 30, 2006

Presentation Outline

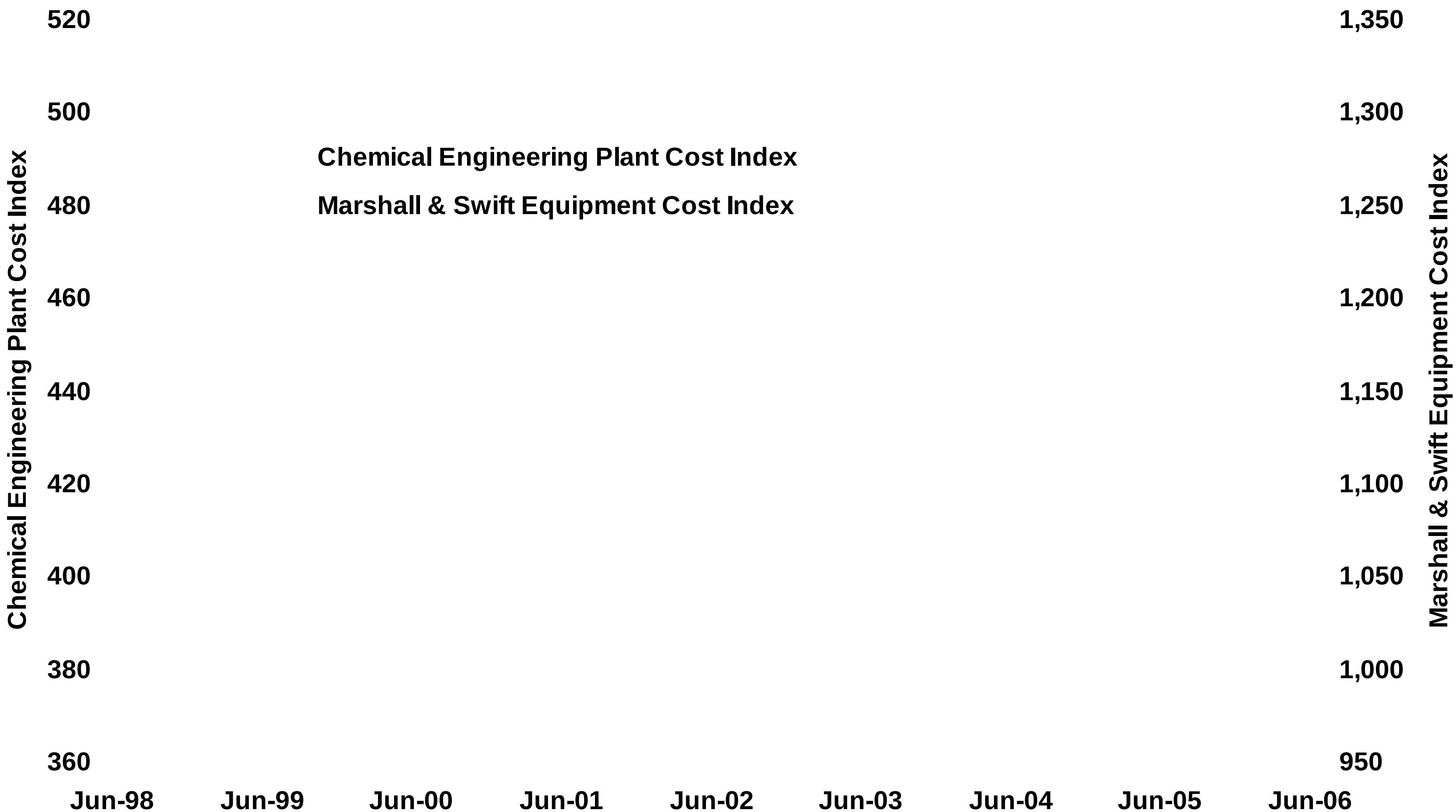
- State of the Industry
- IGCC and PC Cost & Performance Estimates
- Emissions Discussion

Good Capital Cost Information Is Difficult to Obtain!!

- The range of estimates (for a given technology, plant size, coal, and location) available from the listed sources is quite wide
- All EPC firms are very busy and it has proven difficult to contract with them for study work when they have many specific client projects
- All costs are continuing to increase (e.g., structural steel up 15% from 2Q ‘05 to 2Q ‘06). Shortages of key materials and job skills (e.g., engineers, welders) lead to extended project design and construction periods with attendant cost increases.
- Uncertainties regarding 7 FB and 5000 F gas turbine performance, particularly for hydrogen firing on IGCC plants with CO_2 capture. The BP/GE cooperative announcement should help to resolve this.

Construction Cost Indices

Source: Chemical Engineering Magazine, August 2006



Presentation Outline

- State of the Industry
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Sources of Clean Coal Technology Cost and Performance Information

- Previous EPRI Studies 2001–03 (NYPA, WePower, Canadian CPC, WGI, etc.)
- IEA GHG Reports
- DOE NETL Report (Review of May 2006 Draft)
- Wisconsin Public Service Commission DNR IGCC Draft Report
- EPA IGCC and PC (July 2006)
- Confidential ongoing studies with several companies
- Recent work by EPRI for FutureGen Industrial Alliance evaluating multiple possible plant configurations

Notes on SCPC Cost…

- TXU project notice indicates $1,100/kW Total Plant Cost for PRB-fired SCPC plants (buying in bulk may reduce cost per unit)
- Big Stone PC plant (600 MWe) in South Dakota listed at $1.5B ($2,500/kW). Assuming this is TCR and adjusting with the EPRI 1.19 factor, this results in a TPC of $2,100/kW.
- GE Presentation at 2005 GTC indicated $1,460/kW cost assumption for SCPC. Escalated to Jan. 2006$, this is $1,493/kW.
- Other studies are indicating TPCs over $1,500/kW, though few studies have been done recently enough on bituminous coals from a cost perspective to provide clear direction of the numbers.
- EPRI engaging in cost and performance study for SCPC with and without CO_2 capture for various fuel types – Q4 2006 start.

NETL 2006 Cost and Performance of Fossil Energy Power Plants Draft Report

- 600 MW plant COE cost comparison shows ~0-10% higher COE for IGCC vs. SCPC (~$52-57/MWh vs. $52/MWh for eastern bituminous coal).
- Showed Total Plant Cost with eastern coal as $1,355/kW for SCPC and $1,420-1,595/kW for IGCC.
- IGCC analysis included GE, E-Gas and Shell-based performance
- For CO_2 capture, the comparison showed IGCC +25-40% capital and +18-32% HR, and SCPC +75% capital and +43% HR. This COE comparison showed IGCC ~$15/MWh less than SCPC on average.
- Some revised cost estimation is anticipated, which should result in an escalation of the overall cost numbers, but not necessarily the differences between technologies.

Wisconsin PSC IGCC Draft Report

- 600 MW plant COE cost comparison shows ~15% higher COE for IGCC vs. SCPC (~$5/MWh higher with eastern bituminous coal and ~$7/MWh higher with western coal). This differential is similar to several other studies.
- Showed “Capital Cost” with eastern coal as $1628/kW for SCPC and $1872/kW for IGCC. It’s not clear whether this is meant to be TPC or TCR.
- IGCC is treated generically, not as a specifically identified technology
- Effects of IGCC reduced capital and higher availability were estimated
- For CO_2 capture, the comparison was based on IGCC +35% capital and +20% HR, and SCPC +60% capital and +30% HR. This COE comparison showed IGCC ~$10/MWh less than SCPC.

EPA IGCC and PC (July 2006)

- Three coals similar to Ill. #6, PRB, and lignite. Slurry-fed IGCC for Ill. #6 and PRB; dry coal fed for lignite.
- Plant size set arbitrarily at 500 MW
- Heat rates for IGCC and USC look ambitiously low
- On a percentage basis, the differential for IGCC/SCPC TPC and TCR costs are not markedly dissimilar to other studies
- The TPC and TCR estimates are stated in 4Q 2004 dollars. When adjusted to January 2006 (CEPCI factor ~3%), they appear lower than most current estimates (particularly for the lignite PC).
- Executive Summary states IGCC is more effective for CCS than PC with post-combustion capture. Sect. 5 on CCS cites DOE, EPRI, IEA, and CCPC reports from 2000–03 period. (Note: 2003 CCPC reported that for lignite, CCS is better with PC than IGCC.)

EPA IGCC and PC Report July 2006—Summary Tables

Coal	Ill#6	Ill#6	PRB	PRB	Lignite	Lignite
Technology	IGCC slurry	USC PC	IGCC slurry	USC PC	IGCC dry feed	USC PC
Heat rate Btu/kWh HHV	8,167	8,000	8,520	8,146	8,707	9,065
Efficiency	41.8%	42.7%	40.1%	41.9%	39.2%	37.6
TPC $/kW net						
4Q 2004$	1,430	1,355	1,630	1,395	2,000	1,432
Jan. 2006$	1,470	1,395	1,678	1,436	2,060	1,474
TCR $/kW net						
4Q 2004$	1,670	1,529	1,910	1,575	2,350	1,617
Jan. 2006$	1,720	1,574	1,966	1,621	2,420	1,665

GE IGCC Estimates

- GE at October 2005 Conference states a target $/kW no greater than 10% more than an SCPC (which it quoted as $1460/kW), or $1606/kW for 630 MW Radiant Quench design (without spare gasifier). The standard IGCC plant offering is designed to handle a range of bituminous coals from Northern Appalachia and the Illinois Basin.
- Gasifier pressure and cost of Radiant SGC uncertain, particularly for CO_2 capture. As outcome of EPRI FutureGen work estimate, $1850/kW TPC for above range of coals without capture at Midwest location and ~$2300/kW with capture. All in January 2006 dollars. (Assumes single gasifier at 800 psig can fully supply a 7FB gas turbine.)
- EPRI estimate for GE Total Quench for same coals ~$1600/kW TPC without capture and ~$2020/kW with capture in Jan. 2006$. (Assumes single gasifier at 1000 psig can fully supply a 7 FB gas turbine.)
- GE design for PRB or Lignite?

Shell IGCC Estimates—Various Sources

- Shell presentation at CoalFleet meeting in Birmingham, AL, Nov. 2005. At 600 MW net, no CO_2 capture, ~$1600/kW TPC for US Gulf Coast location (coal not specified), and at 500 MW net, with CO_2 capture, ~$2200/kW.
- Translating to standard Midwest location (Factor ~1.12) gives ~$1790/kW and $2460/kW TPC for without and with capture, respectively. Using EPRI factor of 1.19 to translate TPC to TCR yields ~$2130/kW and ~$2930/kW TCR for capture without and with, respectively.
- From EPRI work for FutureGen, Shell with bituminous coal (Illinois #6) at ~600 MW Midwest location estimated TPC ~$1840/kW net and ~$2600/kW TPC net with capture in January 2006 dollars.
- NRG announcement quoted $1955/kW for 750 MW gross Shell IGCC without capture in the Northeast for a "range of coals" (bituminous and subbituminous?). We believe this is TCR and would be $2365/kW on a net basis; using the 1.19 factor, the TPC would be $1987/kW net basis. (EPRI est. for Bit + Subbit is $1940/kW TPC).
- Significant cost reductions (particularly with capture) possible with partial water quench and design for PRB coal only (see Shell paper at Sept. 2005 Pittsburgh conference).

CoP E-Gas IGCC Estimates

- CoP E-Gas reported ranges of nominal 620 MW IGCC costs at October 2005 Conference. For Illinois #6, estimated TCP cost range was $1330–1620/kW, and for PRB $1380–1680/kW for a Midwest location 2005$. Using CEPCI, the estimates become TPC $1365–1660/kW for Ill #6 and $1415–1725/kW for PRB in January 2006$.
- CoP also presented an estimate for PRB at 5000 ft. elevation with a TPC range of $1560–1890/kW in 2005$ or $1620–1940/kW in January 2006$ (without capture). Recent confidential studies have produced estimates at the high end of this range.
- As outcome of EPRI FutureGen work, estimate $1650/kW TPC for Illinois #6 and $1750/kW, if designed for both Ill#6 and PRB (without capture Midwest location in January 2006$). With capture, the estimated TPC costs become ~$2300/kW for Ill #6 and $2425/kW for both Ill#6 and PRB.
- Proposed E-STR tall cylinder design should be capable of higher pressure operation and reduction in capture costs if operated in “Wabash” mode. It should also be better with low-rank coals.

Presentation Outline

- State of the Industry
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Recent Air Permit Applications and Project Information—Units w/o SCR

	Typical IGCC Plant Environmental Performance	Steelhead Energy Southern Illinois Clean Energy Center (IL)	Excelsior Energy Mesaba Energy Project (MN)
Data Source	EPRI UDBS	Permit Application	Public Information
NO_X	0.064 lb/MMBtu (15 ppmvd)	0.059 lb/MMBtu and 15 ppmvd	0.059 lb/MMBtu
SO_2	0.0128 lb/MMBtu (4 ppmv)	0.033 lb/MMBtu	0.022 lb/MMBtu
PM	0.0145 lb/MMBtu (25 ppmvd)	0.00924 lb/MMBtu	0.01 lb/MMBtu
CO	0.039 lb/MMBtu (25 ppmvd)	0.04 lb/MMBtu (25 ppmvd)	0.03 lb/MMBtu
VOC	0.0013 lb/MMBtu (1.4 ppmv)	0.0031 lb/MMBtu (3.3 ppmvw)	0.002 lb/MMBtu

Recent Air Permit Applications and Project Information—Units w/ SCR

	Typical IGCC Plant Environmental Performance	OUC/Southern Orlando Gasification (FL)	ERORA Cash Creek Generation (KY)	ERORA Taylorville Energy Center (IL)	Energy Northwest Pacific Mountain Energy Center (WA)
Data Source	EPRI UDBS	Permit Application	Permit Application & communication with ERORA	Permit Application & communication with ERORA	Public Information
NO_X	0.064 lb/MMBtu (15 ppmvd)	0.08 lb/MMBtu (demo w/ SCR) 0.048 lb/MMBtu (post-demo w/ SCR)	0.0246 lb/MMBtu (w/ SCR)	0.0246 lb/MMBtu (w/ SCR)	0.012 lb/MMBtu (w/ SCR)
SO_2	0.0128 lb/MMBtu (4 ppmv)	0.015 lb/MMBtu	0.0117 lb/MMBtu	0.0117 lb/MMBtu	0.006 lb/MMBtu
PM	0.0145 lb/MMBtu (25 ppmvd)	0.013 lb/MMBtu	0.0063 lb/MMBtu (filterable only)	0.0063 lb/MMBtu (filterable only)	0.01 lb/MMBtu
CO	0.039 lb/MMBtu (25 ppmvd)	0.04 lb/MMBtu	0.036 lb/MMBtu	0.036 lb/MMBtu	0.05 lb/MMBtu
VOC	0.0013 lb/MMBtu (1.4 ppmv)	0.007 lb/MMBtu	0.0011 lb/MMBtu	0.0011 lb/MMBtu	0.003 lb/MMBtu

The Future According to DOE R&D Goals, Canadian Clean Power Coalition, & CURC

	Lowest permit level (lb/MMBtu)	DOE	Canada	CURC Roadmap (2020)
SO_2	0.08 (0.022 CFB)	>99%*	~ 0.01**	0.04 (Bit) SO_3 < 2 ppm
NOx	0.07	<0.01	~ 0.01**	0.01
PM	0.015 (f/c)	0.002	~0.005	< 0.01
Hg	80-90%	95%	0.7 lb/TBtu	80-95%

* 99% @ 3% S coal ~ 25 ppm or ~ 0.05 lb/MMBtu

** ~ 5 ppm @ 3% O_2

Emissions Comparison – State-of-the-Art Coal Combustion, IGCC, and NGCC

Bituminous

0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0

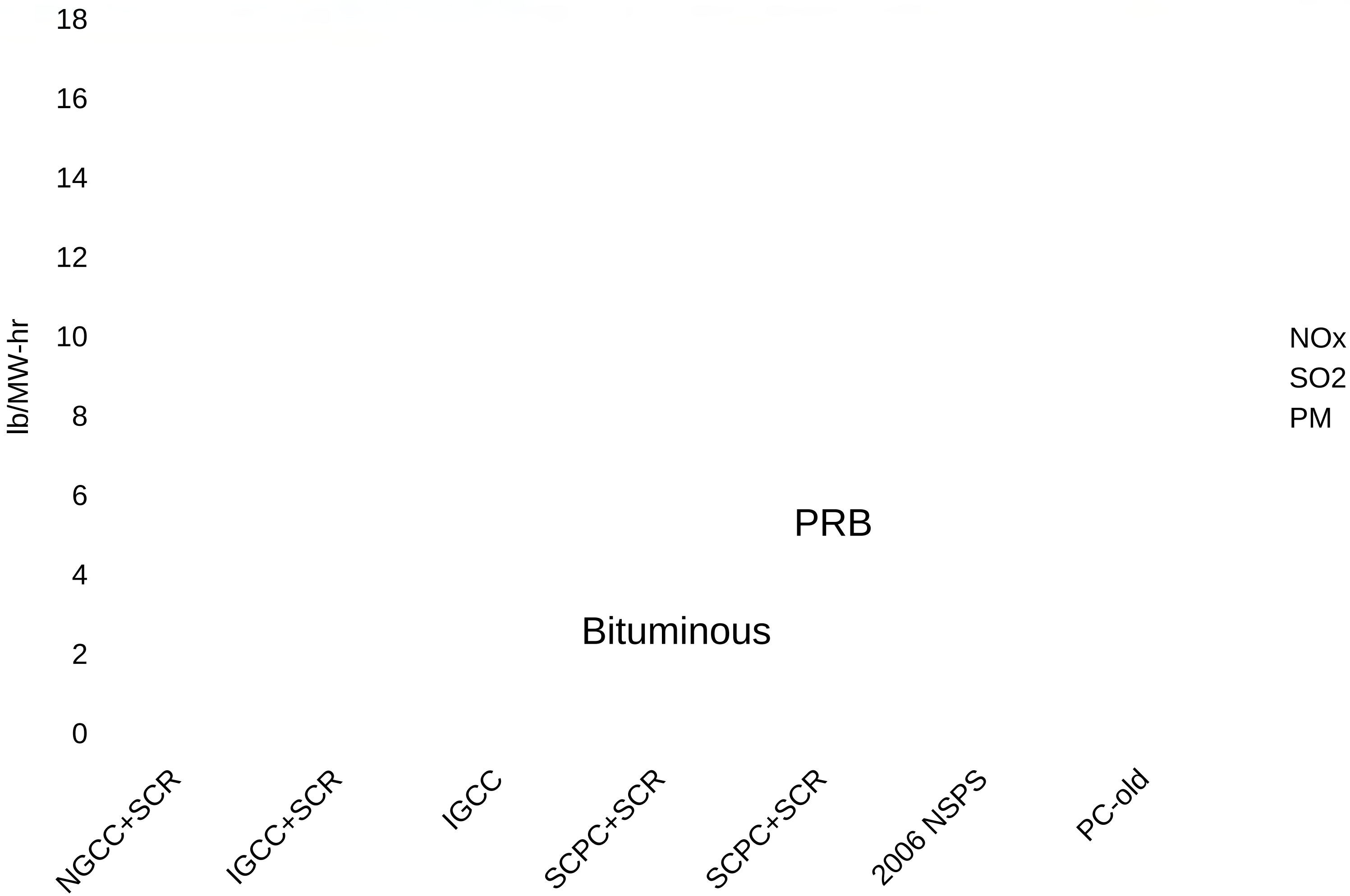
lb/MW-hr

PRB

NOx
SO2
PM

NGCC+SCR
IGCC+SCR
IGCC
SCPC+SCR
SCPC+SCR

Emissions Comparison with Older Coal Plants and Federal Standards



Final Thoughts

- Plant costs are only increasing at this point.
- Advanced PC and IGCC plants both show promise. It will be a “horse race” for market share, and both will provide environmental benefits.
- The “horse race” will extend to fuel selection. Overall cost/benefit analyses will be necessary for each technology
- Cost studies are ongoing and/or planned
  - NETL 2006 Cost and Performance report expected to be published by the end of the year
  - EPRI CoalFleet studies based on Bituminous and Western coals are expected to start in 4Q 2006.

Questions and Discussion

MPUC Docket No. E-6472/M-05-1993
OAH Docket No. 12-2500-17260-2

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Petition of Excelsior Energy Inc. for Approval of a Power Purchase Agreement Under Minn. Stat. § 216B.1694, Determination of Least Cost Technology, and Establishment Of A Clean Energy Technology Minimum Under Minn. Stat. § 216B.1693

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STATE OF MINNESOTA
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FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Petition of Excelsior Energy Inc. for Approval of a Power Purchase Agreement Under Minn. Stat. § 216B.1694, Determination of Least Cost Technology, and Establishment Of A Clean Energy Technology Minimum Under Minn. Stat. § 216B.1693

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION

This matter is before Administrative Law Judges Steve M. Mihalchick and Bruce H. Johnson on the record submitted by the parties in lieu of an evidentiary hearing. The following parties have appeared in this matter:

Byron E. Starns, Leonard, Street and Deinard, 150 South Fifth Street, Suite 2300, Minneapolis, MN 55402, and Thomas Osteraas, Excelsior Energy, 11100 Wayzata Boulevard, Suite 350, Minnetonka, MN 55305, on behalf of Excelsior Energy, Inc.

Christopher B. Clark, Assistant General Counsel, 414 Nicollet Mall, Suite 2900, Minneapolis, MN 55401, and Michael Krikava, Briggs and Morgan, P.A., 2200 I.D.S. Center, 80 South 8th Street, Minneapolis, MN 55402, on behalf of Northern States Power Company d/b/a Xcel Energy.

Valerie Smith, Assistant Attorney General, 445 Minnesota Street, Suite 1400, St. Paul, MN 55101, on behalf of the Department of Commerce.

David R. Moeller, Minnesota Power, 30 West Superior Street, Duluth, MN 55802, on behalf of Minnesota Power.

Carol Overland, Overland Law Office, PO Box 176, Red Wing, MN 55066, on behalf of minncoalgasplant.com (MCGP).

Kevin Reuther, Attorney at Law, Minnesota Center for Environmental Advocacy, 26 East Exchange Street, Suite 206, St. Paul, MN 55101, on behalf of the Minnesota Center for Environmental Advocacy, Izaak Walton League of America—Midwest Office, Wind on the Wires, and Minnesotans for an Energy Efficient Economy (the Environmental Organizations).

Robert S. Lee and Andrew P. Moratzka, Mackall, Crounse & Moore, PLC, 1400 AT&T Tower, 901 Marquette Ave, Minneapolis, MN 55402 on behalf of Xcel Industrial Intervenors.

Todd J. Guerrero and David Sasseville, Lindquist & Vennum, 4200 IDS Center, 80 South 8th Street, Minneapolis, MN 55402-2274 on behalf of Big Stone Unit II Co-Owners.

Richard J. Savelkoul, Felhaber, Larson, Fenlon & Vogt, 444 Cedar Street, Suite 2100, St. Paul, MN 55101 on behalf of the Minnesota Chamber of Commerce.

Eric F. Swanson and David M. Aafedt, Winthrop & Weinstine, P.A., 225 South Sixth St, Suite 3500, Minneapolis, MN 55402 on behalf of Manitoba Hydro.

John E. Drawz, Fredrikson & Byron, P.A., Suite 4000, 200 South Sixth Street, Minneapolis, MN 55402-1425, on behalf of Great Northern Power Development, LLP (Great Northern).

NOTICE

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Minnesota Public Utilities Commission and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed within 20 days of the mailing date hereof with the Executive Secretary, Minnesota Public Utilities Commission, 350 Metro Square, 121 - 7th Place East, St. Paul, Minnesota 55101 or by electronic filing. The Commission may modify the Date for filing exceptions. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions and Order should be included, and copies thereof shall be served upon all parties. If desired, a reply to exceptions may be filed and served within ten days after the service of the exceptions to which reply is made. Oral argument before a majority of the Commission will be permitted upon request Such request must accompany the filed exceptions or reply.

The Minnesota Public Utilities Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judges' recommendation and that said recommendation has no legal effect unless expressly adopted by the Commission as its final order.

STATEMENT OF THE ISSUES

1. Whether Excelsior Energy's Mesaba Unit I (the Project) is an "Innovative Energy Project" within the meaning of Minn. Stat. § 216B.1694, subd. 1.

> The Administrative Law Judges conclude that it is not an "Innovative Energy Project" within the meaning of Minn. Stat. § 216B.1694, subd. 1. Therefore, we also conclude that Excelsior Energy is not entitled to enter into a Power Purchase Agreement (PPA) to provide baseload capacity and energy to Xcel.

2. Whether the Commission should approve, disapprove, amend, or modify Excelsior Energy's proposed PPA.

> Even if the Project were an "Innovative Energy Project," the Administrative Law Judges conclude that the PPA should be disapproved because of the shortcomings discussed in this report. If the PPA is approved by the Commission, it should returned to Excelsior Energy, Xcel Energy, and the Department to negotiate a modified PPA that addresses the shortfalls that have been identified and then be returned to the Commission for final approval.

3. Whether the Project incorporates a "Clean Energy Technology" that "is or is likely to be a least-cost resource, including the costs of ancillary services and other generation and transmission upgrades necessary" and is therefore entitled to supply Xcel with at least two percent of the electric energy that Xcel Energy provides to its retail customers.

> The Administrative Law Judges conclude that neither the technology nor the Project is or is likely to be a least-cost resource. Therefore, we also conclude that the Project is not entitled to supply Xcel with at least two percent of the electric energy Xcel Energy provides to its retail customers.

Based upon the record created in this proceeding, the Administrative Law Judges make the following:

FINDINGS OF FACT

Coal-Burning Power Plants; the Project

1. Pulverized coal (PC) combustion is the most commonly used technology in coal-fired power plants. In PC plants, the coal is ground to a powder then blown with air into the combustion chamber. Piping inside the combustor or a heat exchanger heats water to produce steam to drive a nearby steam turbine and generator.[1]

[1] EE 1016 at 11 (Fluor Report).

2. In Supercritical Pulverized Coal (SCPC) plants, higher temperatures are maintained in the combustor to generate steam at pressures that are above the critical point of water. This results in higher efficiencies than subcritical plants. The first SCPC plants in the United States were constructed in the 1950s. No new units have been placed in service in the United States since the mid 1980s. However, SCPC plants are now planned for Minnesota and surrounding states. New technologies allow SCPC plants to operate at even higher pressures and temperatures, which further improves heat rates. Even more advanced plants are called "Ultra-Supercritical" (USC). A modern 600 MW SCPC plant consists of a single boiler and a single steam turbine and has a full suite of advanced environmental controls such as wet scrubbers, selective catalytic reduction, and mercury removal.[2] In this Report, the term "pulverized coal plants" includes standard PC, SCPC, and USC pulverized coal plants, unless the context indicates otherwise.

3. A combined cycle (CC) plant uses a gas-fired combustion turbine generator to generate electricity, plus it uses excess heat from the combustion in the combustion turbine to create steam to power a steam turbine generator. This combination is considered highly efficient because it uses more of the heat energy from the burning of the gas. It is now a fairly standard configuration. The gas used is usually natural gas (thus, an NGCC), but other gases can also be used.

4. An Integrated Gasification Combined Cycle (IGCC) plant integrates gasification with a combined cycle plant. The gasification process converts coal or other feedstock to a synthesis gas (syngas) comprised primarily of carbon monoxide and hydrogen. The gasification takes place in a gasifier. That is a large vessel capable of containing the high-temperature partial combustion process that breaks down the feedstock and any other ingredients fed into the gasifier, usually water or steam and air or oxygen, into carbon, hydrogen, and oxygen, and then recombines those elements into syngas and other compounds. The syngas is then transported to and burned in a nearby combined cycle gas combustion turbine generator/steam turbine generator combination.[3]

5. Another developing coal technology is "fluidized bed," the most recent generation of which is Circulating Fluidized Bed (CFB) technology. It is described by the U.S. Department of Energy (DOE) as follows:

> Fluidized beds suspend solid fuels on upward-blowing jets of air during the combustion process. The result is a turbulent mixing of gas and solids. The tumbling action, much like a bubbling fluid, provides more effective chemical reactions and heat transfer.
>
> . . .

[2] EE 1016 at 11 (Fluor Report).
[3] EE 1016 at 13-14 (Fluor Report).

The mixing action of the fluidized bed results brings the flue gases into contact with a sulfur-absorbing chemical, such as limestone or dolomite. More than 95 percent of the sulfur pollutants in coal can be captured inside the boiler by the sorbent.

. . .

The popularity of fluidized bed combustion is due largely to the technology's fuel flexibility - almost any combustible material, from coal to municipal waste, can be burned - and the capability of meeting sulfur dioxide and nitrogen oxide emission standards without the need for expensive add-on controls.

. . .

A 2nd generation pressurized fluidized bed combustor uses "circulating fluidized-bed" technology and a number of efficiency enhancement measures. Circulating fluidized-bed technology has the potential to improve operational characteristics by using higher air flows to entrain and move the bed material, and recirculating nearly all the bed material with adjacent high-volume, hot cyclone separators. The relatively clean flue gas goes on to the heat exchanger. This approach theoretically simplifies feed design, extends the contact between sorbent and flue gas, reduces likelihood of heat exchanger tube erosion, and improves SO2 capture and combustion efficiency.

A major efficiency enhancing measure for 2nd generation pressurized fluidized bed combustor is the integration of a coal gasifier (carbonizer) to produce a fuel gas. This fuel gas is combusted in a topping combustor and adds to the combustor's flue gas energy entering the gas turbine, which is the more efficient portion of the combined cycle. The topping combustor must exhibit flame stability in combusting low-Btu gas and low-NOx emission characteristics. To take maximum advantage of the increasingly efficient commercial gas turbines, the high-energy gas leaving the topping combustor must be nearly free of particulate matter and alkali/sulfur content. Also, releases to the environment from the pressurized fluid bed combustion system must be essentially free of mercury, a soon-to-be regulated hazardous air pollutant.[4]

6. Two IGCC demonstration plants are currently operating in the United States: the 250 MW Polk County plant in Florida and the 260 MW Wabash River plant in Indiana. Both plants were partly funded by the Department of Energy and can run on bituminous coal and petroleum coke fuels. The Polk County plant was placed in service in 1996 and utilizes GE (formerly Texaco) gasification technology. The Wabash River

[4] www.fossil.energy.gov/programs/powersystems/combustion/fluidizedbed_overview.html.

plant was placed in service in 1995 and utilizes the ConocoPhillips E-Gas technology that has been selected by Excelsior Energy for the Project.[5]

7. Mesaba Unit I (the Project) will integrate ConocoPhillips E-Gas gasification technology with advanced F-class combustion turbines. This is an IGCC plant that will include two operating "gasification trains" or "gasification islands" (a gasifier and its supporting apparatus), a standby gasification train, two combustion turbines, and a single steam turbine. The spare gasification train is included in order to increase the percent of the time the Project is able to operate, its "availability," to about 92 percent, a very high number. It also provides a backup and the possibility of creating extra syngas that could be sold as a fuel or chemical feedstock. The two or three gasifier trains will feed syngas to the "combined cycle," or "power island," section. There, the syngas will be burned in the two gas combustion turbine generators and the excess heat from those gas turbines will be used to heat water to steam to drive the single steam turbine generator. High pressure steam produced in the gasification trains will also be integrated into the combined cycle, again making efficient use of heat energy that would otherwise be wasted.[6]

8. Gasifiers can be designed to process a wide variety of hydrocarbon fuels, including biomass. The gasifiers for the Project have been designed to operate on subbituminous Powder River Basin (PRB) coal, but will also have the flexibility to receive petroleum coke or bituminous coal fuel as market conditions dictate. The expected net plant output is 603 MW when operating on PRB coal fuel. The net heat rate (a measure power plant thermal efficiency) for the plant when operating on PRB coal is estimated at 9390 btu/kWh on a higher heating value basis. The heat rate will be substantially lower with petroleum coke or bituminous coal fuels, or on natural gas.[7]

9. The Project can also run on natural gas, bypassing the gasifiers and operating as a typical NGCC plant. The Project will be operated in this mode for startup, as back-up when required, and for significant time periods during at least its first three years of operation.[8]

10. In addition to the Mesaba Energy Project, a number of 600 MW IGCC projects have been announced throughout the country.

11. According to an article offered by Excelsior Energy by one expert on IGCC technology,

> Continuing advances in pulverized coal boilers and steam turbines, to supercritical and now ultra-supercritical steam conditions, have largely closed the efficiency gap that once favored IGCC technology.

[5] EE 1016 at 14 (Fluor Report).
[6] EE 1016 at 14 (Fluor Report).
[7] EE 1004 at 19-20; EE 1016 at 14. (Fluor Report).
[8] EE 1020 at 54-55.

> According to the EPRI data, there is less that a 1% difference in heat rate between advanced PC and current IGCC technologies.
>
> In the future, the development of more advanced gasifier technologies is expected to restore that efficiency advantage. Today, however, the economic incentive for going with IGCC is not at all clear.

He suggests that the primary advantages of IGCC technology to be promoted are low emissions, the possibility of carbon dioxide capture, and the possibility of low-cost hydrogen production.[9] Excelsior Energy has adopted that strategy in this case. The evidence in this case suggests, however, that there are constantly evolving advances the efficiency and reduction of emissions for all the methods of using coal to generate electricity. As a result, it is difficult to say that a particular coal technology presents the best option at any particular point. What was true four years ago is not necessarily true today.

12. Moreover, developments in production of energy from renewables, along with increasing public desire and growing legislative requirements for greater use of renewables and less use of coal and other fossil fuels, provide additional complexities to be considered. Of particular relevance here is 2007 Minn. Laws, Chap. 3, Sec. 1, which was enacted February 22, 2007. It raised the Renewable Energy Objectives for electric utilities in Minnesota contained in Minn. Stat. § 216B.1691. Xcel Energy's objectives were set higher than the other electric utilities. Xcel Energy is required to provide at least the following percentages of its total retail electric sales to retail customers in Minnesota with electricity generated by "eligible energy technologies" (solar, wind, small hydroelectric, hydrogen, and biomass) by the end of the year indicated:

(1)	2010	15 percent
(2)	2012	18 percent
(3)	2016	25 percent
(4)	2020	30 percent.

Of the 30 percent in 2020, at least 25 percent must be generated by wind energy conversion systems and the remaining five percent by other "eligible energy technology."

13. The payment terms, specifications, and operating requirements for the Project would be controlled by a Power Purchase Agreement proposed by Excelsior Energy (the PPA). The PPA governs the purchase by Xcel Energy of the entire

[9] EE 1028.18, Harry Jaeger, "*Will IGCC win out over pulverized coal and nuclear steam plants? Near-zero emissions and path to a hydrogen economy, not efficiency and cost advantages, favor coal-based IGCC over pulverized coal steam plants for electric utility power generation*." Gas Turbine World, March-April 2005.

capacity available from the Project, as well as its entire energy output. The term of the PPA is 25 years, from 2011 to 2036, subject to possible extensions.[10]

The IEP and CET Statutes

14. The Legislature enacted both the Clean Energy Technology statute, Minn. Stat. § 216B.1693, and the Innovative Energy Project statute, Minn. Stat. § 216B.1694, in its 2003 Special Legislative Session as part of the 2003 Omnibus Energy Bill.[11]

15. Minn. Stat. § 216B.1693 provides:

216B.1693 CLEAN ENERGY TECHNOLOGY.

(a) If the commission finds that a Clean Energy Technology is or is likely to be a least-cost resource, including the costs of ancillary services and other generation and transmission upgrades necessary, the utility that owns a nuclear generating facility shall supply at least two percent of the electric energy provided to retail customers from Clean Energy Technology.

(b) Electric energy required by this section shall be supplied by the Innovative Energy Project defined in section 216B.1694, subdivision 1, unless the commission finds doing so contrary to the public interest.

(c) For purposes of this section, "Clean Energy Technology" means a technology utilizing coal as a primary fuel in a highly efficient combined-cycle configuration with significantly reduced sulfur dioxide, nitrogen oxide, particulate, and mercury emissions from those of traditional technologies.

(d) This section expires January 1, 2012.

16. Minn. Stat. § 216B.1694, provides:

216B.1694 INNOVATIVE ENERGY PROJECT.

Subdivision 1. **Definition**. For the purposes of this section, the term "innovative energy project" means a proposed energy-generation facility or group of facilities which may be located on up to three sites:

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[10] Exhibits EE 1023 (public) and EE 1024 (non-public) are the December 2005 version of the PPA filed with the application. Some changes were proposed in Excelsior Energy's surrebuttal testimony, which appear in EE 1041 and EE 1063. Those changes, plus some others proposed by Excelsior Energy in its Reply Brief, were incorporated into a Final Proposed Power Purchase Agreement attached as Exhibit B (non-public) to the Reply Brief (the Final PPA or Ex. B). The Final PPA also declassified many items formerly claimed to be trade secret. Unless the context indicates otherwise, references in this report to "the PPA" are to the Final PPA. Power purchase agreements are also known as purchased power agreements.

[11] Act of May 29, 2003, ch. 11, art. 4, 2003 Minn. Laws 1st Spec. Sess. 1661.

(1) that makes use of an innovative generation technology utilizing coal as a primary fuel in a highly efficient combined-cycle configuration with significantly reduced sulfur dioxide, nitrogen oxide, particulate, and mercury emissions from those of traditional technologies;

(2) that the project developer or owner certifies is a project capable of offering a long-term supply contract at a hedged, predictable cost; and

(3) that is designated by the commissioner of the Iron Range Resources and Rehabilitation Board as a project that is located in the taconite tax relief area on a site that has substantial real property with adequate infrastructure to support new or expanded development and that has received prior financial and other support from the board.

Subd. 2. **Regulatory incentives**. (a) An innovative energy project: (1) is exempted from the requirements for a certificate of need under section 216B.243, for the generation facilities, and transmission infrastructure associated with the generation facilities, but is subject to all applicable environmental review and permitting procedures of chapter 216E;

(2) once permitted and constructed, is eligible to increase the capacity of the associated transmission facilities without additional state review upon filing notice with the commission;

(3) has the power of eminent domain, which shall be limited to the sites and routes approved by the Environmental Quality Board for the project facilities. The project shall be considered a utility as defined in section 216E.01, subdivision 10, for the limited purpose of section 216E.12. The project shall report any intent to exercise eminent domain authority to the board;

(4) shall qualify as a "clean energy technology" as defined in section 216B.1693;

(5) shall, prior to the approval by the commission of any arrangement to build or expand a fossil-fuel-fired generation facility, or to enter into an agreement to purchase capacity or energy from such a facility for a term exceeding five years, be considered as a supply option for the generation facility, and the commission shall ensure such consideration and take any action with respect to such supply proposal that it deems to be in the best interest of ratepayers;

(6) shall make a good faith effort to secure funding from the United States Department of Energy and the United States Department of Agriculture to conduct a demonstration project at the facility for either geologic or terrestrial carbon sequestration projects to achieve reductions in facility emissions or carbon dioxide;

(7) shall be entitled to enter into a contract with a public utility that owns a nuclear generation facility in the state to provide 450 megawatts of baseload capacity and energy under a long-term contract, subject to the approval of the terms and conditions of the contract by the commission. The commission may approve, disapprove, amend, or modify the contract in making its public interest determination, taking into consideration the project's economic development benefits to the state; the use of abundant domestic fuel sources; the stability of the price of the output from the project; the project's potential to contribute to a transition to hydrogen as a fuel resource; and the emission reductions achieved compared to other solid fuel baseload technologies; and

(8) shall be eligible for a grant from the renewable development account, subject to the approval of the entity administering that account, of $2,000,000 a year for five years for development and engineering costs, including those costs related to mercury-removal technology; thermal efficiency optimization and emission minimization; environmental impact statement preparation and licensing; development of hydrogen production capabilities; and fuel cell development and utilization.

(b) This subdivision does not apply to nor affect a proposal to add utility-owned resources that is pending on May 29, 2003, before the Public Utilities Commission or to competitive bid solicitations to provide capacity or energy that is scheduled to be on line by December 31, 2006.

Procedural History

17. Excelsior Energy, Inc., is an independent energy development company based in Minnetonka, Minnesota, that is incorporated under the laws of the State of Minnesota. Excelsior Energy, Inc., and its subsidiary, MEP-I LLC (jointly, Excelsior or Excelsior Energy), is proposing to license, construct, own, and operate the Mesaba Energy Project Unit I. Unit I is a solid fuel IGCC power plant located in northeastern Minnesota with an initial capacity installation of 603 MW(net). Unit II of the Mesaba Energy Project is an identical IGCC power plant planned to be built adjacent to Unit I in a second phase. Unless the context indicates otherwise, reference in this report to “the Project,” “Mesaba 1,” or “the Facility” is only to Unit I.

18. Northern States Power Company d/b/a Xcel Energy (NSP, Xcel Energy, or Xcel) is engaged primarily in the business of generating, transmitting, and distributing electrical power and energy in the states of Minnesota, Wisconsin, North Dakota and South Dakota. Xcel Energy owns the two nuclear generation facilities that currently exist in Minnesota. The Project is comparable in output to Xcel Energy’s Monticello

nuclear generating plant, which has an output of approximately 600 MW, or about ten percent of Xcel Energy's customers' electric energy requirements.[12]

19. As of 2002, Xcel Energy provided service to slightly more than half of Minnesota's almost two million non-farm residential electric customers. It served an even higher proportion of Minnesota's commercial electric customers.[13] Its Minnesota service areas cover a large portion of the southern half of Minnesota.

20. Beginning in late 2004 and throughout 2005, Excelsior discussed with Xcel Energy the potential terms and conditions of a Power Purchase Agreement to govern the sale of the output of the Project. Despite their efforts, consensus was not reached.

21. On December 27, 2005, Excelsior filed a Petition asking the Commission to open a contested case proceeding to:

> a. approve, amend, or modify the terms and conditions of a proposed power purchase agreement that Excelsior has submitted to Xcel Energy under Minn. Stat. § 216B.1694;
>
> b. determine that the coal-fueled Integrated Gasification Combined Cycle ("IGCC") power plant that Excelsior plans to construct in northern Minnesota is, or is likely to be, a least-cost resource, obligating Xcel Energy to use the plant's generation for at least two percent of the energy supplied to its retail customers, under Minn. Stat. § 216B.1693; and
>
> c. determine that, under the terms of Minn. Stat. § 216B.1693, at least 13% of the energy supplied to Xcel Energy's retail customers should come from the IGCC plant by 2013.

22. The Commission issued an Order on April 25, 2006, which provided that the Commission has jurisdiction over Excelsior's petition under Minn. Stat. §§ 216B.1693 and 216B.1694 and referred the matter to the Office of Administrative Hearings for a contested case proceeding. The Commission also requested that its Executive Secretary ask the Minnesota Pollution Control Agency for its assistance in addressing the technical and environmental issues in this case.

23. In the Second Prehearing Order dated June 2, 2006, the ALJs directed that consideration of the whether at least 13 percent of the energy supplied to Xcel Energy's retail customers should come from the Units I and II by 2013 would be

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[12] In the Matter of the Application of NSP for a CON for an IFSFI at its Monticello Generating Plant, *ALJ Findings of Fact, Conclusions of Law, and Recommendation*, Aug. 4, 2006, at Finding No. 26., Adopted by MPUC Oct. 23, 2006, PUC Dkt No CN-05-123, OAH Dkt. No. 12-2500-16407-2.

[13] Minn. Dept. of Commerce, *2002 Utility Data Book*, at 26 and 33. Available at http://www.state.mn.us/mn/externalDocs/Commerce/Utility_Data_Book,_1965-2000__030603120425_UtilityDataBook65thru02.pdf.

deferred until the second phase of the hearing process. The early stages of that phase are now under way.

24. On June 5, 2006, Commission Executive Secretary Burl W. Haar sent a letter to Commissioner Corrigan of the Minnesota Pollution Control Agency pursuant to the Commission's April 25, 2006 Order. The letter requested assistance in addressing the technical and environmental issues in this case, and specifically noted that one of the factors the Commission must consider under Minn. Stat. § 216B.1694 is the emission reductions achieved by the proposed IGCC plant compared to other solid fuel baseload technologies.

25. Xcel Industrial Intervenors (XLI) filed a Notice and Motion for Summary Judgment with the ALJs on September 18, 2006. XLI argued that no genuine issues of material fact exist and that, as a matter of law, the Commission cannot approve Excelsior's proposed PPA with Xcel Energy because the proposed PPA involves the sale of power well in excess of the 450 MW allowed by Minn. Stat. § 216B.1694, subd. 2(a)(7). XLI also argued that Excelsior has failed to offer evidence that its Clean Energy Technology is a "least-cost resource," within the meaning of Minn. Stat. § 216B.1693(a). On September 25, 2006, Excelsior filed a Response and Memorandum in Opposition to XLI's Motion for Summary Disposition. Excelsior argued that the provisions of the statutes are not inextricably linked as XLI contends, and that the 450 MW limitation in the IEP Statute is not a ceiling on either the size of the plant it may construct or on the amount of power it may generate at that plant. Excelsior further argued that the public interest determinations referred to in the IEP and CET Statutes are not one and the same but are separate and are to be conducted for separate purposes. Finally, Excelsior argued that whether Excelsior's proposed project demonstrates that Clean Energy Technology is a least-cost resource within the meaning of the CET Statute is not a prerequisite to Commission approval of its proposed PPA under the IEP Statute, and that whether IGCC technology is a least-cost resource within the meaning of the CET Statute involves genuine issues of material fact.

26. Also on September 25, 2006, MCGP filed a Motion for Partial Summary Judgment with the ALJs. MCGP argued that no genuine issues of material fact exist and that, as a matter of law, Excelsior's West Range Site does not meet the requirements of Minn. Stat. § 216B.1694, subd. 1(3), and that Excelsior is not entitled to a PPA based on a project constructed on the West Range Site. MCGP indicated that in order to meet the statutory definition of an Innovative Energy Project to be entitled to a PPA pursuant to said section, a project must be located "on a site that has substantial real property with adequate infrastructure to support new or expanded development." MCGP conceded that the IEP Statute requires the Commissioner of Iron Range Resources ("IRR") to designate sites that have adequate infrastructure, and that the IRR Commissioner has, in fact, designated the West Range Site as having adequate infrastructure. MCGP argued that the IRR Commissioner's designation of that site was erroneous or fraudulent, and therefore, as a matter of law, Excelsior cannot construct its project on that site. Excelsior filed a Memorandum in opposition to MCGP's motion. Excelsior argued that (1) the legislature delegated discretion to designate sites that would be suitable for an IEP project to the IRR Commissioner, and that said designation

is not subject to a collateral attack; (2) even if the IRR Commissioner's designation were reviewable in this proceeding, her exercise of discretion can only be reversed upon a showing that it was an abuse of discretion or was arbitrary or capricious; and (3) whether the West Range Site has adequate infrastructure to support new or expanded development involves disputed issues of fact. Xcel filed a memorandum in response to MCGP's motion on October 3, 2006. Xcel argued that whether Excelsior's project satisfies statutory requirements involved genuine issues of material fact that should be heard.

27. The ALJs heard argument on the motions on October 5, 2006. The Minnesota Chamber of Commerce and MCGP indicated support for XLI's Motion for Summary Disposition. The ALJs issued an Order on Motion for Summary Disposition on October 25, 2006. The Order's memorandum provided that the only proposal pending for a PPA is a proposal for the sale and purchase of 450 MW of baseload capacity. The Order also concluded that whether the Commission should approve that PPA does not directly involve consideration of whether Excelsior's IGCC technology is a least-cost resource, but does involve evaluation of the four specific factors set forth in Minn. Stat. § 216B.1694 subd. 2(a)(7), and other aspects of the public interest. The Order also concludes that the issue of whether Xcel Energy must purchase 153 MW (603 MW less 450 MW) from Excelsior pursuant to Minn. Stat. § 216B.1693 does involve a determination of whether Excelsior's IGCC technology is a least-cost resource. The ALJs determined that these considerations involve issues of fact, and therefore, XLI's Motion For Summary Disposition was denied.

28. The October 25, 2006, Order also denied MCGP's Motion for Partial Summary Disposition, concluding that as a matter of law the Commission lacks jurisdiction to determine whether the IRR Commissioner's designation of the West Range Site is erroneous or fraudulent. However, the ALJs did find that the infrastructure costs may be relevant to the Commission's determination under the CET Statute of whether Excelsior's IGCC technology is a least-cost resource.

29. At a November 16, 2006, prehearing conference, the parties stipulated to the admission of the pre-filed testimony and waived cross-examination of all witnesses for the evidentiary hearing, which had been scheduled to commence on November 20, 2006.

30. Public hearings were held on December 18, 2006, in St. Paul, on December 19, 2006, in Hoyt Lakes, and on December 20, 2006, in Taconite.

31. Excelsior Energy, Xcel Energy, and the Department all express a willingness to engage in further negotiations.

Innovative Energy Project, Minn. Stat. § 216B.1694, subd. 1

Innovative Generation Technology; subd. 1(1)

Use of Coal in an IGCC

32. Large scale IGCC plants the size of the Mesaba Project have not been built until recently, and the Project will include the most recent developments in efficiency and emission controls to make it state of the art. That alone does not make it innovative. What is new in the Project is the configuration. To produce 600 MW, it uses two gas combustion turbines, possibly because the maximum output of combustion turbines generators is less than 300MW. It provides the syngas from three gasifiers that are only slightly larger than the gasifier that has been operating at Wabash River, thus minimizing technical problems of upsizing the gasifiers while providing abundant capacity for producing the syngas required by the combustion turbines. It recovers heat energy from the two combustion turbines and the three gasifiers to create steam for a single steam turbine. This configuration is unique and innovative.

33. Minn. Stat. § 216B.1694, subd. 1(1), first requires a determination of whether the Mesaba Project uses "coal as a primary fuel in a highly efficient combined-cycle configuration." The Project does use solid fuel in a combined cycle configuration and that combined cycle is considered highly efficient. While the Project is intended to operate primarily on syngas that it creates from various forms of "solid fuel," it can use natural gas in the combined cycle power island as an alternative.[14] Thus, there is an issue of what percentage of the total operation will be on natural gas. There is also an issue not raised by the parties as to whether coal will be the primary fuel for the gasifiers.

34. The Final PPA does not expressly require the use of coal because it speaks in terms of using "solid fuel," not "coal," and never defines the term "solid fuel." It appears that all the parties and witnesses use "solid fuel" to mean any combustible fuel normally in a solid, not liquid or gaseous, state. They used it primarily to refer to coal of various types and grades, and petroleum coke. But there was also reference to municipal and industrial waste, biomass, and hydrocarbons in general being used to fuel gasifiers.

35. If the Project consistently used a 50% or greater petroleum coke blend over any particular period, it would not be using coal as its primary fuel during that period because petroleum coke is not coal. It is not derived from coal as is "coke." It is derived from petroleum.[15] The PPA, as currently drafted, places no express limitation on Excelsior Energy's ability to feed other non-coal "solid fuels" into the gasifiers.

[14] Final PPA, Section 3.5 and Appendix A.

[15] *See* International Union of Pure and Applied Chemistry, *Compendium of Chemical Terminology,* definition of petroleum coke; available at http://www.iupac.org/goldbook/P04522.pdf.

36. Excelsior Energy's preliminary fuel design studies investigated using 100% Illinois No. 6 bituminous coal and different blends of PRB subbituminous coal and petroleum coke, from 0% to 100% of each. The studies showed that the optimal cost of production would result from using the Illinois No. 6 or any of the PRB/petroleum coke blends up to 50% petroleum coke.[16] Based upon the studies, the feedstock design specifications proposed in the PPA include 100% PRB coal, a 50% blend of PRB coal and petroleum coke, and 100% Illinois No. 6 coal.[17]

37. The PPA requires Excelsior Energy to design its fuel procurement strategies to optimize the fuel costs of the Project, consistent with and subject to "Good Utility Practice" and performance parameters set forth in the PPA. Its determination is subject to review by a Fuel Subcommittee comprised of a representative each from Excelsior Energy and Xcel Energy, which must apply the same standards.[18] Nothing in the PPA requires them to ensure that the majority of the fuel for the gasifiers is coal. According to the Project Description, the cost of delivered PRB coal has been increasing since 1989, while the price of "PetCoke" has been declining.[19] Similarly, Excelsior's fuel expert Ralph Olson testified that there is likely a surplus of petroleum coke such that it will be an excellent low cost fuel allowing the Project to minimize fuel costs by using it as an alternative or a supplement to coal when market conditions dictate.[20] There is a real possibility that fuels consisting of 50 to 100 percent petroleum coke will become the best value. The PPA would not prevent Excelsior Energy and the Fuel Subcommittee from choosing such blends at that time. On the contrary, the PPA would require it.

38. Based on the foregoing, there is no assurance in the Final PPA that the Project will primarily use coal as a fuel as required by Minn. Stat. § 216B.1694, subd. 1(1), even when it is operating on solid fuel being gasified into syngas and then burning the syngas in the combustion turbines.

39. The parties focused on the ability of the Project to run on natural gas like a standard NGCC plant as creating the more significant issue as to whether coal would be the primary fuel. William Blazer of the Minnesota Chamber of Commerce expressed concern that the PPA does not require coal to be the primary fuel. He was not referring to the lack of definition of solid fuel, but to the terms of the PPA that allow operation in the NGCC mode without any guarantee that it would not be run in that mode extensively or exclusively.[21] Karen T. Hyde of Xcel Energy had similar concerns about the lack of control over use of natural gas.[22]

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[16] EE 1020 at 109-110.
[17] Final PPA, Ex. G at 3.
[18] Final PPA, Sections 5.5 and 10.5(C).
[19] EE 1020 at 108, fig. 40.
[20] EE 1161 at 5.
[21] MCC 7000 at 7-8.
[22] XE 2005 (public) at 16-17.

40. To address this issue, Excelsior Energy has proposed terms in the PPA that impose financial penalties on it for using natural gas instead of solid fuel.

41. As proposed in the Final PPA, about two-thirds of the total monthly payment to be made by Xcel Energy is for "Contract Capacity," which is essentially a payment for the costs of designing and constructing the Project and having its output available to Xcel Energy and its customers. The tariff provisions in Article 8 of the Final PPA provide for reduced capacity payments for all hours during which natural gas or a natural gas-syngas blend is used, after a three-year ramp-up period.[23] Pursuant to those revised tariff provisions, for example, for all hours when the plant operates solely on natural gas, Excelsior would only receive 35% of the full capacity payment under the proposed PPA.[24] On a 50-50 blend of syngas and natural gas, Excelsior Energy would receive only 69.2% of the full capacity payment.[25]

42. The Capacity Price downward adjustment for use of natural gas in Section 8.1 of the PPA is on a sliding scale. The "Natural Gas Factor" (NGF) is 25% the first year, 40% the second, 50% the third, and 65% thereafter. The intent of the NGF is to reduce the credit given to energy produced from natural gas in calculating the Capacity Availability Factor. That reduction is designed to be the least in year one and the greatest in year four and thereafter. Therefore, the percentage of energy produced from natural gas is multiplied by 1-NGF. As discussed above, Excelsior Energy witness Renee Sass demonstrated that if, after the three-year ramp-up period, the Project ran 50% of the time on natural gas and 50% of the time on solid fuel-derived syngas during a month in which it had total availability of 91%, the Capacity Availability Factor would be 69.2% and Xcel Energy would be charged 69.2% of the capacity charge rather than 100%.[26] If that same calculation were made using the Natural Gas Factor and "Ramp Up Factor" for the first year of operation, the CAF would be 130.2% and Xcel Energy would be charged the maximum 110.0% of the capacity charge for that month. In the second year the CAF and charge would be 103.7% of the capacity charge. In the third year the CAF and charge would be 86.2% of the capacity charge.

43. This provision was designed to assure that Xcel Energy pays only an approximation of the capital costs of a natural gas facility to the extent that the Project operates solely using natural gas. The reduction in capacity payments to Excelsior for any hour during which the plant does not operate on 100% syngas creates a financial incentive to for Excelsior to maximize solid fuel operation.[27] However, because of the Ramp Up Factor, it does not become significant until the third year of operation. Moreover, Excelsior Energy and its ratepayers would still have to pay the full fuel payment, which would include payment for all the natural gas used.

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[23] Some of the original provisions in Article 8 of the proposed PPA (EE 1024) were revised in the Rebuttal Testimony of Thomas J. Osterhaas (*See* EE 1041) and the Surrebuttal testimony of Renee J. Sass (*See* EE 1062 and EE 1063).
[24] EE 1062 at 5 and EE 1063.
[25] EE 1062 at 6-7.
[26] EE 1062 at 6-7.
[27] EE 1062 at 5.

44. In addition, Section 11.1(B)(2) of the Final PPA provides that an "Event of Default" occurs if, after 48 months of operation, Excelsior Energy fails to maintain a capacity availability factor (CAF) of greater than seventy percent "on a twelve month rolling average basis."[28] It is not clear, but that could mean that it would take another twelve months to build up such an average. According to Excelsior Energy, in order to meet the seventy percent requirement, the Project must operate on syngas rather than solid fuel a majority of the time.[29] Since this would be a Section 11.1(B) event of default, Excelsior Energy would have 30 days to commence curing the default and would then be required to continue to work on the cure "diligently." It could take more than five years before the PPA could be terminated for not using solid fuel as the primary fuel. Moreover, if the Project always ran 51% on solid fuel and 49% on natural gas (rather than 50 - 50), application of Excelsior's revised formula would result in Xcel Energy paying in excess of 70% of the Capacity Price on a rolling 12-month basis, and therefore the right to terminate the proposed PPA would not be triggered. This provision provides little assurance that the Project will use not solid fuel, let alone coal, as its primary fuel.

45. As drafted, the Final PPA does not mandate the primary use of coal, as required by the IEP and CET Statutes. There are incentives in the Final PPA that encourage the use of solid fuel and penalize the use of natural gas, but they do not assure it. There is no requirement at all that the solid fuel be "coal." The PPA allows the Project a minimum of four years to achieve primary operation on solid fuel. Even if it required coal, four years is too long to meet the statutory requirement that coal be used as the primary fuel. Since there is no assurance in the PPA that the Project will use coal as a primary fuel as required by Minn. Stat. § 216B.1694, subd. 1(1), the Project does not meet the requirements of that clause.[30]

Degree of Emissions Reduction

46. Minn. Stat. § 216B.1694, subd. 1(1), also requires that the Project result in "significantly reduced sulfur dioxide, nitrogen oxide, particulate, and mercury emissions from those of traditional technologies." This emission reduction language in Minn. Stat. § 216B.1694, subd. 1(1), is similar to language in Minn. Stat. § 216B.1694, subd. 2(a)(7),—namely, "emission reductions achieved compared to other solid fuel baseload technologies." The legislative directives to make both inquiries are contained in the same statute and are aimed at accomplishing the same legislative purpose and goals. The two provisions must therefore be read *in pari materia*. Reading the two sets of

[28] EE 1024 at 37-38.
[29] *See* EE 1062 at 7.
[30] In light of the State goals of increasing the use of renewables and reducing the use of fossil fuels, it might be preferable if the PPA penalized the use of natural gas without rewarding the use of coal. That would allow Excelsior Energy to consider some portion of biomass, industrial waste, or municipal waste in it fuel mix for the gasifiers or the use of a synthesis gas produced by someone else mixed with its own syngas in its combustion turbines. For example, nearby paper mills may be able someday to produce combustible Dimethyl Ether (DME) by gasifying their pulping-process residue. *See* http://www1.eere.energy.gov/biomass/black_liquor_gasification.html. However, this approach might require a change to the IEP and CET Statutes.

requirements together, only "solid fuel baseload technologies" should then be considered in comparing the Project's emissions to those of "traditional technologies." Only traditional coal-fired plants meet this requirement.

47. SCPC and USC pulverized coal plants meet the definition of "traditional" solid fuel technology because they burn coal in a combustor to create steam that powers a steam turbine that powers a generator. Their technology uses much higher combustion and steam temperatures and pressures that increase efficiency and have other benefits, and they have several add-on technologies as well, but the basic process remains the same.

48. CFB plants burn a wide variety of solid fuels. The newest designs run a combustion turbine off the flue gas from the combustor and may include a gasifier section within the combustor to create additional "fuel gas" (a/k/a "syngas") for the combustion turbine. From the description by DOE quoted in Finding No. 5 above, it appears that an enhanced, second generation CFB plant is actually a form of IGCC and may meet the definition of an "innovative generation technology" under Minn. Stat. § 216B.1694, subd. 1(1). In any event, it would not be a "traditional technology" under that clause.

49. Excelsior, Xcel Energy, and the Minnesota Pollution Control Agency each submitted expert opinions and supporting evidence pertaining to comparative emission reductions. Each of their sets of comparisons compares the projected emissions of Excelsior's Project with other actual or hypothetical plants or projects. But all three of them, for the most part, used different hypothetical plants or projects for comparison and rely on somewhat different emission modeling approaches and parameters. It is therefore not possible to completely reconcile all three results with one another.

50. At Excelsior's request, ICF Consulting modeled the emissions that will likely be produced by the Project. ICF Consulting's emission estimates for the Project were derived from available data for the Wabash River IGCC plant in Terre Haute, Indiana, and from the Louisiana Technology, Inc., facility in Plaquemine, Louisiana. ICF Consulting also modeled emission estimates for a hypothetical Alternative SCPC plant for comparison.[31] Both models were developed using the REMSAD modeling system.[32] ICF Consulting's initial modeling showed the following emission rates (in tons per year for $S0_2$, NO_x, and PM_{10}. and in pounds per year for mercury):

[31] EE 1011 at 2-7.
[32] *Id*. at 2-1 and 2-2.

Emission	Project's IGCC Facility	Hypothetical Alternative SCPC Facility
SO_2	447	1,752
NO_x	1,227	1,538
PM_{10}	174	439
Mercury	17.92 lbs/yr.	24.61 lbs./yr.

51. Excelsior's initial emission modeling was based on a Project with generation capacity of 531 MW. Excelsior subsequently scaled the initial modeling to a Project with 606 MW generation capacity, which is approximately what Excelsior is now proposing. Excelsior has presented the following scaled up emission data in comparison with the emission rates presented in its Air Permit Application and in comparison with its hypothetical Alternative SCPC facility. (The data was presented as maximum long term hourly average rates in terms of pounds per hour):

Emission	Project's IGCC Facility	Air Permit Application	Hypothetical Alt. SCPC Facility
SO_2	123	128	431
NO_x	339	321	377
PM_{10}	48	51	108

52. Excelsior has compared its Project's sulfur dioxide emission rates with the sulfur dioxide emission rates of eight existing large coal-fueled generating plants in Minnesota. (All data is expressed as pounds per gross megawatt hour):[33]

Plant	$S0_2$ Emission Rate (lbs./MWh_{gross})
Alan S. King (pre-MERP)	16.30
Alan S. King (post-MERP)	1.18
Black Dog	3.70
Boswell Energy Center	5.72
Hoot Lake	7.29
Sherburne County	3.24
Laskin Energy Center	5.15
Taconite Harbor Energy Ctr	7.57
The Project	*0.23*

53. Excelsior has also compared its Project's nitrogen oxides emission rates with the nitrogen oxides emission rates of eight existing large coal-fueled generating

[33] EE 1004 at 29. The source of data for existing plants is the USEPA's Clean Air Market Emission Tracking System.

plants in Minnesota. (Again, all data is expressed as pounds per gross megawatt hour):[34]

Plant	NO_x Emission Rate (lbs./MWh_{gross})
Alan S. King (pre-MERP)	7.65
Alan S. King (post-MERP)	0.99
Black Dog	8.24
Boswell Energy Center	3.73
Hoot Lake	4.76
Sherburne County	3.26
Laskin Energy Center	7.39
Taconite Harbor Energy Ctr	4.64
The Project	*0.54*

54. Excelsior also compared its Project's mercury emission rates with the mercury emission rates of eight existing large coal-fueled generating plants in Minnesota. (All data is expressed as pounds per gross trillion watt hour):[35]

Plant	Mercury Emission Rate (lbs./$TrillionWh_{gross}$)
Alan S. King (pre-MERP)	7.65
Alan S. King (post-MERP)	0.99
Black Dog	8.24
Boswell Energy Center	3.73
Hoot Lake	4.76
Sherburne County	3.26
Laskin Energy Center	7.39
Taconite Harbor Energy Ctr	4.64
The Project	*0.54*

55. No data on particulate matter emissions were available to Excelsior comparison with existing large coal-fueled generating plants in Minnesota.

56. Excelsior has also compared its SO_2, NO_x, and particulate matter emissions with what were, in its opinion, "the nation's cleanest coal plants" for reducing SO_2 emissions.[36] It arrived at the following comparison with the lowest permitted SO_2 emission rates on the RLBC database versus the worst case for the Project (expressed as pounds per million BTUs):

[34] *Id.*

[35] EE 1004 at 30. The source of data for existing plants is the USEPA's 2004 Form R report from its Toxic Release Inventory.

[36] Excelsior indicated that it selected the plants for comparison by conducting a review of the U.S. EPA's RACT/BACT/LAER clearinghouse (RBLC) and other government agency databases. Excelsior explains its methodology in EE 1004 at 30. In other evidence, Excelsior described the plants to which comparisons were made as "recently permitted SCPC facilities." *See* EE 1084 at 3.

Plant	SO_2	NO_x	PM
AES Puerto Rico	0.022	0.100	0.0300
Sevier Power Co. NEVCO	0.022	0.100	0.0154
MDU Gascoyne	0.038	0.090	0.0275
The Project (Worst Case)	*0.025*	*0.057*	*0.0100*[37]

57. Excelsior also compared its SO_2, NO_x, and particulate matter emissions with a different set of what were, in its opinion, "the nation's cleanest coal plants" for reducing NO_x emissions. It arrived at the following comparison of sources with the lowest permitted NO_x emission rates on RLBC versus the worst case for the Project (terms of pounds per million BTUs):

Plant	SO_2	NO_x	PM
Black Hills Corp	0.100	0.0100	0.0120
Bull Mountain	0.100	0.0030	0.0120
Mid-American CBEC4	0.100	0.0036	0.0250
The Project (Worst Case)	*0.025*	*0.0032*	*0.0100*[38]

58. Excelsior also compared its SO_2, NO_x, and particulate matter emissions with yet a third set of what were, in its opinion, "the nation's cleanest coal plants" for reducing PM emissions. It arrived at the following comparison of sources with the lowest permitted PM emission rates on RLBC versus the worst case for the Project (expressed as pounds per million BTUs):[39]

Plant	SO_2	NO_x	PM
JEA Northside	0.150	0.0900	0.0110
Black Hills Corp	0.100	0.0100	0.0120
Bull Mountain	0.100	0.0030	0.0120
The Project (Worst Case)	*0.025*	*0.0032*	*0.0100*

59. Excelsior also compared its SO_2, NO_x, and particulate matter emission rates with the estimated emission rates of the Big Stone Unit II facility. Comparisons were made in terms of pounds per hour:

Plant	SO_2	NO_x	PM
Big Stone II	551	386	165
The Project (Worst Case)	*148*	*324*	*57*[40]

60. Excelsior presented a bar graph comparing the Project's worst case annual mercury emissions compared with those of three recently permitted SCPC

[37] EE 1004 at 31.
[38] EE 1004 at 32.
[39] EE 1005 at 33.
[40] EE 1086 at 19.

plants. Emission rates were compared in terms of pounds per year. The exact quantitative emission rates for each of the facilities were not recorded on the bar graph. The approximate emission rates recorded on the graph were as follows: approximately 30 lbs. per year for the Project; approximately 200 lbs. per year for the NRG Cajun facility; permit limits of approximately 160 lbs. per year for the Mid American facility; and permit limits of approximately 50 lbs. per year for the Elm Road facility.[41]

61. Xcel presented data comparing the Project's SO_2, NO_x, and particulate matter emissions with newly proposed SCPC plants. It arrived at the following comparison of sources with the lowest emission rates versus the worst case for the Project (also expressed as pounds per million BTUs):[42]

Plant	SO_x	NO_x	PM
Calaveras Station	0.060	0.0500	0.0220
Desert Rock	0.060	0.0600	0.0200
Black Hills Corp	0.100	0.0700	0.0120
Bull Mountain	0.100	0.0700	0.0120
Mid-American CBEC4	0.100	0.0700	0.0250
The Project (Worst Case)	*0.025*	*0.0032*	*0.0100*

62. Xcel also presented the following data (also in terms of pounds per million BTUs) comparing the Project's emissions with a "Hypothetical SCPC" plant for purposes of comparison:[43]

Plant	SO_x	NO_x	PM
Hypothetical SCPC Plant	0.080	0.0700	0.0200
The Project (Worst Case)	*0.025*	*0.0032*	*0.0100*

63. It is the opinion of Michael G. Cashin, Minnesota Power's expert witness, that IGCC technology is slightly more favorable than modern pulverized coal plants in terms of reducing mercury, SO_2, and NO_x emission reductions. Mr. Cashin analyzed the data submitted by Excelsior as demonstrating comparisons with conventional coal plants of particulate removal approaching 99.9%, with modern pulverized coal plant demonstrating particulate removal approaching 99.8%. He also analyzed the data submitted by Excelsior as demonstrating NO_x reductions compared with conventional coal uncontrolled emissions at about 91%, with modern pulverized coal plant demonstrating NO_x reductions of 88%. Mr. Cashin further analyzed the Project's SO_2 emission reductions at 98% versus controlled conventional pulverized coal compared to modern pulverized coal at 94%. Finally, Mr. Cashin considered the mercury removal

[41] EE 1004 at 28.
[42] XE 2023 at 14-16.
[43] *Id.*

performance of IGCC as being about equivalent to the performance of conventional pulverized coal technology equipped with emerging mercury control technology.[44]

64. At the request of the Commission and the Department, the Minnesota Pollution Control Agency (MPCA) participated in this proceeding as a non-party consultant on matters relating to the Project's air emissions. Subsequently and at the Department's request, the MPCA prepared a report comparing of the Project's emissions with other IGCC and state-of-the-art coal-fired electric generating technologies.[45]

65. The MPCA report first compared the net thermal efficiency of the Project with that of the Wabash facility (another IGCC facility) and three pulverized coal facilities. Thermal efficiency is the measure of a facility's ability to efficiently extract heat from coal (or oil or gas) and convert it from thermal to mechanical and finally to electric energy. Increasing thermal efficiency means that more electrical power can be generated with the same amount of coal and, depending on the emission control technology, fewer emissions. In other words, a plant with a higher heat efficiency produces fewer emissions for each unit of electricity produced.[46]

66. The MPCA concluded that the thermal efficiency of the Project operating on subbituminous coal would be 36.3%. The Project's thermal efficiency would, therefore, be lower than the thermal efficiency of the Wabash IGCC plant (40% on bituminous coal) but higher than the thermal efficiency of the proposed Desert Rock SCPC plant (34.3%) and the SWEPCO Hempstead Co. plants (35.9%).[47] The MPCA also concluded that the thermal efficiency of the Project's plant was somewhat lower than what the EPA has modeled for the performance of "generic" IGCC plants (40%), SCPC plants (37.9%) and USC plants (41.9%).

67. The MPCA also compared the Project's SO_2, NO_x, and particulate matter emissions with three other existing facilities and with EPA's three types of future "generic" plants. The MPCA presented its comparisons as the percentages by which the other actual or hypothetic facilities varied from the Project's emissions.[48] The MPCA employed pounds per net megawatt hour as the unit of comparison.[49] In response to comments on its initial submission, the MPCA corrected some of its calculations in a December 5, 2006, submission.[50] Those calculations are incorporated here.

[44] MP 4004 at 4-5.
[45] MPCA 8000.
[46] MPCA 8000 at 2.
[47] *Id*. at 3.
[48] In other words, the Project's emissions represented a baseline of "0," with the emissions of the other facilities expressed in terms of percentages greater or less than that baseline of 0.
[49] In one set of comparisons, Excelsior used pounds per *gross* megawatt hour as the unit of comparison. The MPCA considered pounds per *net* megawatt hour as the unit of comparison to be the better measure. See discussion in MPCA 8001.
[50] MPCA 8001.

Plant	NO_x	SO_2	PM
Wabash	+150%	+265%	+26%
Existing PC with BACT controls	+36%	+284%	+48%
Desert Rock SCPC	+12%	0.0030	+18%
SWEPCO Hempstead USC PC	+24%	+289%	+18%
EPA "generic" subbituminous SC	+1%	+139%	+28%
EPA "generic" subbituminous IGCC	-30%	-58%	-29%
EPA "generic" subbituminous USC	-9%	+233%	+16%

68. The MPCA also compared the Project's mercury emissions with three other existing facilities and with EPA's three types of future "generic" plants. Again, the MPCA presented its comparisons as percentages by which the other actual or hypothetic facilities varied from the Project's emissions. The MPCA employed of pounds per net megawatt hour as the unit of comparison:

Plant	Mercury
Existing PC with BACT controls	+10.918%
Desert Rock SCPC	+302.608%
SWEPCO Hempstead USC PC	-12.168%
EPA "generic" subbituminous SC	-12.952%
EPA "generic" subbituminous IGCC	-23.880%
EPA "generic" subbituminous USC	-20.951%

69. Because of the ease of removing sulfur from syngas prior to its combustion in a combustion turbine generator, IGCC plants, such as the Project, emit far less SO_2 than other traditional solid fuel baseload technologies.[51]

70. With regard to reducing SO_2, the Project is expected to underperform what the EPA estimates will be the future emission reduction performance of IGCC technology, while the Project is expected to significantly outperform EPA's estimates of what will be the future SO_2 emission reduction performance of SC and USC technologies with regard to SO_2. However, the Project is expected to only slightly outperform those technologies in terms of reducing PM emissions, and slightly underperform them in terms of reducing NO_X emissions.

71. Nitrogen oxide (NO_X) emissions are a function of both the nature of the generating technology and the efficiency of add-on control equipment.[52] The Wabash IGCC plant has much higher NO_X levels than the Project (150%) because it lacks specific NO_X controls. Other existing pulverized coal plants have only slightly higher NO_X levels than the Project will have, and EPA generic SC and USC plants have slightly lower levels.

[51] MPCA 8000 at 4.
[52] *Id.*

72. The particulate matter emissions of other traditional solid fuel baseload technologies (ranging from 18% to 73%) are generally higher than the Project's estimated particulate emissions.

73. IGCC technology is not inherently better at controlling mercury emissions than traditional solid fuel baseload technologies. Rather, the rate at which mercury is emitted during combustion depends primarily on the presence or absence of add-on mercury controls, with the state-of-the-art being activated carbon injection. The Project is being designed with activated carbon injection technology that will remove 90% of mercury emissions. Of the comparisons that MPCA made to existing pulverized coal plants, the Desert Rock plant's mercury emissions are expected to exceed those of the Project by over 300% because that plant is only proposing 80% mercury emission control and has not committed to activated carbon injection technology. On the other hand, the mercury controls at the SWEPCO Hempstead USC PC plant enable it to remove slightly more mercury than the Project is expected to remove.[53]

74. In summary, in comparison with traditional solid fuel baseload technologies, the Project's emissions of sulfur dioxide and particulates will be significantly reduced. Its nitrogen oxides and mercury emissions will be significantly reduced in comparison only with older existing coal-fueled plants, but not in comparison with newer, but still "traditional," SCPC coal plants with state-of-the-art controls.

75. Because the Project reduces sulfur dioxide and particulates so well, it can be said that, on an overall basis, it significantly reduces the listed emissions compared to traditional plants. However, the statute appears to require all the listed emission to be reduced. Since the Project does not significantly reduce emissions of two of the four pollutants required to be significantly reduced by Minn. Stat. § 216B.1694, subd. 1(1), it does not meet the requirements of that clause.

Certification as to Hedged, Predictable Cost; subd. 1(2)

76. Minn. Stat. § 216B.1694, subd. 1(2), requires that Excelsior Energy certify that the Project is "capable of offering a long-term supply contract at a hedged, predictable cost." Excelsior Energy has made that certification and claims that nothing more is required.[54] However, Minn. Stat. § 216B.1694, subd. 1(2), requires something different than an "official" designation, such as the one in Minn. Stat. § 216B.1694, subd. 1(3). Subd. 1(2) refers to a "certification" by a private party who is seeking a government benefit in a proceeding that is before the Commission under statutes that require the Commission to examine the terms of that contract and to consider the public interest. The IEP Statute must also be construed in a way that gives effect to all of its provisions.[55] Therefore, the Commission has the authority and duty to look beyond Excelsior's certification that it is "capable of offering a long-term supply contract at a hedged, predictable cost" in order to determine whether or not that is, in fact, the case.

[53] MPCA 8000
[54] EE1002.
[55] Minn. Stat. § 645.15 (2006).

77. Excelsior Energy claims that its proposed PPA offers a hedged, predictable, and stable price because (1) the capacity price is fixed over the life of the contract; (2) coal prices are stable; and (3) The Project's ability to run on a variety of fuels and its low emissions profile are inherent price hedges.[56]

78. The capacity price is the largest component of the total monthly payment that Xcel Energy will pay, about 68 percent of it.[57] It is based largely on the Engineering, Procurement, and Construction (EPC) contract cost. That is stated as a trade secret, forecasted, target cost in the proposed Final PPA, to be adjusted and fixed when the EPC contract is executed. It is likely to be larger by some unknown amount when it is fixed. The capacity price also includes unreimbursed transmission costs, which are relatively minor, but also not fixed at this point.[58] Overall, the capacity price is not hedged or predictable at this point. Excelsior Energy's position is that its "predictability" should be determined after the capacity price is fixed. Xcel Energy argues that it should be determined now.

79. Subd. 1(2) speaks in terms of being "capable" of offering a contract at a hedged, predictable cost. It does not require that a hedged and predictable cost be offered today. What must be judged today is the capability of doing so under the terms of the PPA. It is more usual for PPAs to include EPC-type costs up front, but Excelsior Energy has chosen to provide an estimate of EPC costs that will be fixed relatively soon. That process leaves some cost issues unresolved now, but does not make it impossible to eventually offer a contract at a hedged, predictable cost at a reasonable point in the future. The arguments of Xcel Energy, MCGP, the Department, and others about the potentially large, unpredictable increases in the EPC contract cost are more relevant to the issue of financial risks to ratepayers discussed below.

80. The monthly capacity payment under the PPA is stated as the capacity price, times the final certified capacity, times the lesser of the Capacity Availability Factor or 1.1. Since the capacity price and certified capacity will be fixed numbers, and 1.1 is a fixed number, this formula states a maximum price for the capacity payments. The CAF is approximately the percentage of the energy produced from syngas compared to total energy produced, subject to various adjustments. As that percentage goes down, the monthly capacity payment goes down.[59] Since the PPA sets a maximum price, the monthly capacity payment may be considered hedged and predictable. It will go down the first four years because of allowances in those early years, then remain flat for the remaining 21 years of the PPA.[60] If any further adjustments are made because of using natural gas, they would be reductions in the capacity payment.

[56] EE 1004 at 16-21.
[57] EE 1006, figs. 1 and 3.
[58] Final PPA, Section 8.1.
[59] Final PPA, Section 8.1.
[60] EE 1006, fig. 3.

81. The PPA also requires variable and fixed operating and maintenance payments. They are stated in fixed trade secret amounts per MWh and are indexed quarterly by the "implicit price deflator" for the gross domestic product (GDPIPD), a statistic published by the U.S. Department of Commerce. They are also subject to review and adjustment every five years by the Operating Committee, but Excelsior Energy has modified the Final PPA so that neither party may unilaterally adjust them. The variable and fixed O&M payments are projected by Excelsior Energy to start out at about 14 percent of Xcel Energy's total monthly payment and likely increase gradually because of the escalator.[61] By definition and from the point of view of a ratepayer, the GDPIPD is not predictable, so neither are the O&M payments. However, the impact of changes in the GDPIPD on the total monthly payment will not likely be very great.

82. The Final PPA provides that all the costs for fuel and fuel delivery during a month must be paid in a monthly fuel payment. The fuel payment also includes all revenues and expenses collected or paid for any "environmental attribute adjustments" and all revenues and expenses associated with the sale or disposal of any byproducts. Excelsior Energy estimates that fuel costs will start at about 18 percent of Xcel Energy's total monthly payment and likely increase gradually over the life of the PPA.[62]

83. There is no dispute that coal prices have historically been more stable than natural gas prices. PRB coal and Illinois Basis coal have generally tracked along similar lines, with PRB coal being somewhat less expensive. Petroleum coke is even lower priced and has trended gradually downward over the last 15 years, but there has been some upward pressure lately.[63] It can reasonably be expected that a generating plant running on coal will have more stable fuel costs than one running on natural gas.

84. Excelsior Energy claims that the monthly fuel payment it charges Xcel Energy will be capable of being offered at a hedged, predictable cost because Excelsior Energy will be able to obtain fuel at a hedged, predictable cost. According to its fuels expert, Ralph Olson, "Excelsior has taken prudent steps to ensure that it can implement an aggressive fuel supply plant and strategy by maximizing its alternatives" for coal and petroleum coke, and for fuel transportation. In addition, Olson notes that the Fuel Subcommittee provisions of the PPA will allow Xcel Energy to direct the optimization of the fuel flexibility of the Project and the alternative transportation options provided by the two railroads serving the Project.[64] Other things being equal, having options available may create opportunities for reduced prices. Having a fuel committee is not a particular advantage for the Project, even with Xcel Energy on it. It is to be expected that any power plant buying that much fuel will have experts on staff and advising it on fuel needs and buying strategies.

[61] EE 1006, figs. 1 and 3; Final PPA, Sections 8.2, 8.4, and 10.9. It is not clear in Section 8.4 whether the multiplier is Contract Energy or Contract Capacity.
[62] Final PPA, Section 8.3; EE 1006, figs. 1 and 3.
[63] EE 1020 at 108, fig. 40; XE 2022, Sched.3.
[64] EE 1161 at 2 and 8-15.

85. As defined by Xcel Energy's fuels expert Thomas C. Canter, "hedging" means insuring against unfavorable changes in price on one side by entering into counterbalancing arrangements on the other side. Simply having options available will not provide price certainty due to uncertainty of coal supply and transportation services that are provided only on the margin or incrementally to The Project.[65]

86. Excelsior Energy has no coal or petroleum coke supply or transportation commitments at this time to hedge against future cost increases, nor does it anticipate beginning to negotiate any for another three to four years. Until it develops a portfolio of fuel and transportation agreements, Excelsior Energy will have no hedge against future coal prices through an assured source for future fuel at a known price.[66]

87. When Excelsior Energy does start negotiating its agreements, it may have problems developing long-term commitments with fuel suppliers if it attempts to threaten switching to another supplier. There is already projected to be increasing demand for coal from all areas and the needs of a new buyer like the Project will add to that increasing demand. Fuel suppliers will need to expand to meet that need and will not rush to provide low prices. Likewise, there is projected to be a continuing shortage of rail capacity for the delivery of coal for the foreseeable future. The large coal producers and railroads have large market power, and consolidation in the PRB and Illinois Basin has increased that power. There is no evidence that there are significant changes in price differentials between PRB and Illinois coal that can be exploited by spot purchases. Thus, Excelsior Energy may have considerable difficulty obtaining fuel at favorable prices.[67]

88. Finally, the ability to operate the Project on natural gas provides no fuel price hedge or predictability because natural gas is more expensive than coal and subject to greater price swings. It will not be a particularly effective negotiating tool with coal suppliers because they will know the use of natural gas will necessarily be temporary and expensive, because of the statutory requirement to use primarily coal, and because of the market power of the coal suppliers.

89. In summary, because of the Project's large need for coal and the current and projected economies of coal production and coal transportation, it cannot be found that Excelsior Energy is capable of obtaining fuel for the Project at a favorable price. However, Excelsior Energy is certainly capable of negotiating a portfolio of agreements of varying terms so that its fuel costs would be hedged, and relatively predictable and stable.

90. Excelsior Energy proposed passing through "environmental attribute adjustments" and the revenues and expenses associated with the sale or disposal of any byproducts because it believes they both will eventually produce significant revenue to the Project. Xcel Energy commented that the cost pass throughs were unusual in

[65] XE 2022 at 4.
[66] EE 1208; XE 2021 at 7; XE 2022 at 3-4; MP 4006 at 12-13; MP 4013 at 12-13.
[67] XE 2021 at 3-8; XE 2022 at 5-10; MP 4006 at 11-13; MP 4013 at 10-17.

their extent and in that they would pass through Xcel Energy's fuel cost adjustment and, thus, be paid directly by its ratepayers. In response, Excelsior Energy has offered to modify the PPA so that it has responsibility for all costs and benefits of byproducts and environmental attributes associated with compliance with laws and regulations in effect on the date of signing of the PPA.[68]

91. Despite the fact that these costs and revenues would be added to the fuel payment and would make it quite variable, they should not be considered as part of the price predictability issue because it is logically a separate issue. If the Project has costs for meeting environmental requirements, they should be considered as part of the cost of the Project. They are included in the cost estimates below. If the Project realizes revenues from environmental credits, they should be applied to reduce the costs. Potential revenues from selling sulfur and other byproducts should be used to reduce costs as well, but it is only fair that any additional costs for such production be included as well. This pass through language should be retained, but with some provision allowing Xcel Energy to review the reasonableness of the expenditures.

92. Overall, about 80 percent of the total monthly payment will be at a fixed price with an escalator that will likely result in a gradual increase. That is not hedged, but it is predictable and roughly stable. About 20 percent of the monthly cost will be for fuel costs that are not likely to be hedged, predictable, or stable under Excelsior Energy's current plan to rely on short-term contracts. However, Excelsior Energy is capable of developing fuel and transportation contracts that will provide for hedged, predictable, and stable fuel costs. Therefore, the Project is capable of offering a long-term supply contract at a hedged, predictable cost as required by Minn. Stat. § 216B.1694, subd. 1(2).

Designation by IRRB Commissioner; subd. 1(3)

93. Minn. Stat. § 216B.1694, subd. 1(3), requires that the Project be designated by the Commissioner of the Iron Range Resources and Rehabilitation Board as a project that is located in the taconite tax relief area on a site that has substantial real property with adequate infrastructure to support new or expanded development and that has received prior financial and other support from the board.

94. The Commissioner has so designated both the East Range and the West Range sites. Therefore, the Project meets the requirements of Minn. Stat. § 216B.1694, subd. 1(3).

Qualification as an Innovative Energy Project

95. Since the Project fails to meet the requirements of Minn. Stat. § 216B.1694, subd. 1(1), it is not an "Innovative Energy Project" for purposes of Minn. Stat. § 216B.1694.

[68] XE 2005 at 22-23, EE 1039 at 27.

96. Minn. Stat. § 216B.1694, subd. 2(a)(4), provides that an Innovative Energy Project shall qualify as a "Clean Energy Technology" as defined in section 216B.1693. That definition is the same as the first requirement for an "Innovative Energy Project" under Minn. Stat. § 216B.1694, subd. 1(1). Therefore, by definition and this statute, if a project meets the requirements to be an "Innovative Energy Project," it would also fulfill the definitional requirements of a "Clean Energy Technology." Similarly, if a project does not meet the requirements of Subd. 1(1), it would not fulfill the definitional requirements of a "Clean Energy Technology" either.

97. Since the Project is not an Innovative Energy Project, it does not qualify under Minn. Stat. § 216B.1694, subd. 2(a)(4), as a "Clean Energy Technology" as defined in section 216B.1693. Also, for the same reasons the Project fails to meet the requirements of Minn. Stat. § 216B.1694, subd. 1(1), it fails to meet the definitional requirements of a "Clean Energy Technology" under Minn. Stat. § 216B.1693(c).

Entitlement to PPA, Minn. Stat. § 216B.1694, subd. 2(a)(7)

98. Again, Minn. Stat. § 216B.1694, subd. 2(a)(7), states that an Innovative Energy Project . . .

> shall be entitled to enter into a contract with Xcel to provide 450 megawatts of baseload capacity and energy under a long-term contract, subject to the approval of the terms and conditions of the contract by the commission. The commission may approve, disapprove, amend, or modify the contract *in making its public interest determination*, taking into consideration the project's economic development benefits to the state; the use of abundant domestic fuel sources; the stability of the price of the output from the project; the project's potential to contribute to a transition to hydrogen as a fuel resource; and the emission reductions achieved compared to other solid fuel baseload technologies. [Emphasis added.]

99. Since the Project is not an Innovative Energy Project, it is not entitled under Minn. Stat. § 216B.1694, subd. 2(a)(7), to enter into a contract with Xcel to provide baseload capacity and energy.

Evaluation of the PPA

100. The following findings shall apply if it is found and concluded by the Commission that the Project is entitled to enter into a contract with Xcel to provide baseload capacity and energy under a long-term contract, subject to the approval of the terms and conditions of the contract by the Commission.

101. Senator David J. Tomassoni from Senate District 5, a chief author of the IEP and CET Statutes, submitted comments to provide some background relating to the passage of the IGCC statutes. Senator Tomassoni explained that the statutes were enacted as part of the legislation, supported by Xcel Energy, authorizing additional cask storage at Prairie Island and new casks at the Monticello nuclear plant. The Iron Range delegation supported the proposed legislation authorizing the casks as part of a

package deal that included the IGCC statutes. In 2002-2003, Xcel began talking about a need for new coal base load plants, and the company told the Legislature that it needed 450 megawatts of new baseload in 2010, 450 in 2012, and 900 in 2015. According to Senator Tomassoni, the Legislature exempted the project from a certificate of need to expedite the construction of the plant and directed the PUC not to entertain Xcel's argument that the plant is not needed, which to him is essentially an argument that the growing electric need in Minnesota can be met by natural gas plants. Senator Tomassoni argues that the Legislature has already made the contentious policy decisions about big energy resources after weighing Xcel's arguments along with all other parties involved, and the IGCC statutes do not contemplate the PUC going back over those broad policy decisions that were considered and made by the State's elected officials. According to Senator Tomassoni:

> The IGCC statutes direct the PUC to confirm the benefits of the technology and, on the part of the statute that deals with the Clean Energy Technology, to confirm that the IGCC technology looks cost effective as one of a portfolio of technologies to meet the State's base load needs over the next century. As you can tell by reading the statutes, the Legislature expected that IGCC would look more expensive than conventional coal plants at the outset, but over time, improvements that will happen and changing emission limits would lead to the IGCC technology being more attractive in the long run.

102. Senator Tomassoni also noted that the Legislature was focused on the emissions reductions that could be achieved by the IGCC technology, especially mercury, particulate matter and sulfur emissions, and felt that the ability to capture and sequester carbon dioxide in the future was an added benefit. Senator Thomas Saxhaug from Senate District 3 also praised the Project and the new IGCC technology, as well as the economic benefit it would bring to the area.

103. Minn. Stat. § 216B.01, contains the Legislature's findings with regard to the Commission's regulation of public utilities and provides, in part:

> It is hereby declared to be in the public interest that public utilities be regulated as hereinafter provided in order to provide the retail consumers of natural gas and electric service in this state with adequate and reliable services at reasonable rates, consistent with the financial and economic requirements of public utilities and their need to construct facilities to provide such services or to otherwise obtain energy supplies, to avoid unnecessary duplication of facilities which increase the cost of service to the consumer and to minimize disputes between public utilities which may result in inconvenience or diminish efficiency in service to the consumers

104. Excelsior Energy is not a "public utility" under Chap 216B, so it is not regulated by the Commission and Minn. Stat. § 216B.01 does not apply to it. However, the statute's requirement to judge the public interest does apply to the PPA. Minn. Stat. § 216B.1694, subd. 2(a)(7), expressly invokes the Commission's statutory duty to

consider the impact the PPA will have on the broader public interest. And it does so in addition to listing five specific factors that relate to a contract for the electricity from the Project. To hold otherwise would render the phrase, "in making its public interest determination," in the statute superfluous. The subdivision must be read so as to give effect to all of its provisions.[69] In addition, the Commission's general responsibilities to regulate Xcel, Minnesota Power, and other utilities to the extent they are affected by the PPA, broaden the Commission's public interest determinations under the CET and IEP Statutes because of the very substantial impacts of the PPA upon those utilities and upon their many retail consumers in this state.

105. Moreover, in considering the impact of the PPA upon Xcel Energy's ratepayers, Minn. Stat. § 216B.03, requires the Commission to ensure that the rates are just and reasonable, to set rates to encourage energy conservation and renewable energy use, and to resolve any doubt as to reasonableness in favor of the consumer.

106. Dr. Eilon Amit of the Department analyzed several aspects of the PPA. In addition to the specified considerations listed in Minn. Stat. § 216B.1694, subd. 2(a)(7), he analyzed the public interest by applying the same criteria used by the Department to analyze all other PPAs for the Commission, namely:

a. Ratepayers must be appropriately protected from the operational risk associated with the PPA;

b. Ratepayers must be appropriately protected from the financial risks of the PPA; and

c. The purchase price to be paid by ratepayers for the electric energy and capacity must be reasonable.[70]

Dr. Amit also considered the indirect financial costs to ratepayers caused by the PPA's impacts on Xcel Energy's financial health, specifically, its credit rating, cost of long-term debt, cost of common equity, and overall cost of capital.[71] All these criteria are within the scope of Minn. Stat. §§ 216B.01 and 216B.03 and are applicable in this matter.

107. Xcel Energy witnesses John J. Reed and George E. Tyson, II, presented a similar list of criteria: (1) effect on customer rates, (2) reasonableness of terms in comparison to industry norms, (3) risks imposed on Xcel's customers, (4) effect on credit rating, (5) effects on costs of capital, and (6) resulting effects on costs of service.[72] Again, these criteria relate to providing consumers in this state with adequate and reliable services at reasonable rates, consistent with the financial and economic

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[69] Minn. Stat. § 645.15 (2006); *See Owens v. Federated Mut. Implement & Hardware Ins*., 328 N.W.2d 162, 164 (Minn. 1983).
[70] DOC 3000 at 7-9.
[71] DOC 3014 at 15-20.
[72] EX 2017 at 3-4; XE 2010 at 2.

requirements of Xcel Energy. Thus, they are thus within the scope of Minn. Stat. §§ 216B.01 and 216B.03 and are applicable in this matter.

108. Because Excelsior Energy is not regulated by the Commission, the PPA is the only vehicle available to ensure performance of the Project and reasonableness of rates paid by Xcel Energy's ratepayers. In the PPA, the only mention of subsequent review by the Commission is a statement in the Fuel Subcommittee provision that the parties "acknowledge and agree that all fuel costs associated with the operation of the Facility will ultimately be subject to prudency review by the MPUC."[73] However, this reference appears to be only to Xcel Energy's Fuel Clause Adjustment and does not create any direct regulation by the Commission of the fuel mix used by the Project. In its latest revisions to the PPA, Excelsior Energy added a one-time Commission review that would be triggered if the final construction costs exceed the target construction cost estimate by a certain percentage.[74] Given the Commission's extremely limited oversight of Excelsior Energy and the PPA, it is necessary that all potential issues be addressed as completely as possible in the PPA before it is approved.

109. In sum, the IEP Statute does, as Senator Tomassoni suggested, direct the Commission to confirm the benefits of the technology and confirm that the PPA will be cost effective. In order to do so, it is necessary to evaluate the Project and the PPA considering:

The Project's economic development benefits to the state;

The Project's use of abundant domestic fuel sources;

The stability of the price of the Project's output;

The Project's potential to contribute to a transition to hydrogen as a fuel resource;

The Project's emission reductions achieved compared to other solid fuel baseload technologies;

The protection of ratepayers from operational risks associated with the PPA;

The protection of ratepayers from financial risks associated with the PPA;

The protection of ratepayers from indirect financial costs caused by the PPA's impact on Xcel Energy's financial health; and

The reasonableness of the cost of the PPA.

[73] EE 1024, Section 10.5(C).
[74] Final PPA, Schedule I.

Economic Development Benefits to the State

110. James A. Skurla is the Acting Director of the Bureau of Business and Economic Research of the University of Minnesota-Duluth's Labovitz School of Business and Economics (hereafter Labovitz School). In September 2005, the Labovitz School produced a report entitled *The Economic Impact of Constructing and Operating an Integrated Gasification Combined-Cycle Power-Generation Facility on the Iron Range* (Labovitz School Report), at Excelsior's Request and under Mr. Skurla's direction.[75]

111. The Labovitz School Report yielded estimates of the numbers of jobs that the Project would both directly and indirectly create on the Iron Range and statewide, as well as the dollar value of economic activity that the Project would generate on the Iron Range and statewide.[76] It did so by employing the IMPLAN modeling system, using Excelsior's estimates of the values of direct expenditures for construction and operation of the Project, with a net output of 531 MW, as the original modeling inputs.[77] The Labovitz School Report estimated the following impacts of the Project on Minnesota's economically-depressed Iron Range and the state at large:[78]

a. $1.04 billion in direct spending on construction;

b. $300 million in direct spending on operations during a typical plant-year, recurring for the life of the plant;

c. An additional non-recurring $533 million in increased business and household spending across the Arrowhead region, which will ultimately result in a non-recurring $762 million in increased spending throughout the State, driven by spending on construction;

d. An additional recurring $66 million in increased spending across the Arrowhead region, which will ultimately result in a recurring $91 million in increased spending throughout the state, generated by spending on operations;

e. Over the course of the 42-month construction period, full-time, part-time and temporary construction jobs peak at almost 3,000;

f. A total of over 100 full-time, part-time and temporary jobs in operations;

g. An additional 1,682 new full-time, part-time and temporary jobs during the peak year in other sectors across the Arrowhead region, as a result of the creation of construction jobs; and

[75] EE 1107 (Skurla Supplemental Testimony); *see also* EE 1009 (Labovitz School Report).
[76] *Id*.
[77] EE 1009 at 4-5.
[78] *Id*. at iv.

h. An additional 290 new full and part-time jobs in other sectors across the region, caused by the creation of jobs in the typical year of operation.

112. In September 2006, the Bureau prepared an update to the Labovitz School Report (Updated Labovitz School Report) based on updated assumptions that Excelsior provided to the Labovitz School. Those updated assumptions were: (1) $1.6 billion in direct spending on construction; (2) $440 million of indirect spending on operations;[79] and a Project, with a net output of 603 MW. Based on those assumptions, the Updated Labovitz School Report estimated the following impacts of the Project on Minnesota's Iron Range and the state at large:[80]

a. $1.6 billion in direct spending on construction;

b. $440 million in direct spending on operations during a typical plant-year, recurring for the life of the plant;

c. An additional non-recurring $399 million in increased business and household spending across the Arrowhead region, which will ultimately result in a non-recurring $640 million in increased spending throughout the State, driven by spending on construction;

d. An additional recurring $95 million in increased spending across the Arrowhead region, which will ultimately result in a recurring $130 million in increased spending throughout the state, generated by spending on operations;

e. Over the course of the Mesaba One construction period 2008-2011, full-time, part-time and temporary construction jobs peak at almost 1,555;

f. A total of over 107 full-time, part-time and temporary jobs in operations;

g. An additional 1,966 new full-time, part-time and temporary jobs during the peak year in other sectors across the Arrowhead region, as a result of the creation of construction jobs; and

h. An additional 143 new full and part-time jobs in other sectors across the region, caused by the creation of jobs in the typical year of operation.

[79] *Id*.

[80] *The Economic Impact of Constructing and Operating an Integrated Gasification Combined-Cycle Power-Generation Facility on the Iron Range, UPDATE 2006: Mesaba One Impacts (Updated Labovitz School Report).* EE 1110.

113. The Labovitz School prepared estimates of the economic impact of the Project with a 531 MW capacity and with a 603 MW capacity, but did not prepare estimates of the economic impacts of a Project with a 450 MW capacity.[81]

114. It is the expert opinion of Timothy J. Sheesley, an economist employed by Xcel, that the Economic Report prepared by the Labovitz School used a standard model and normal modeling procedures to arrive at direct and indirect positive benefits. It was, however, his further opinion that in order to assess the full development impacts of the Project, a study must take a broader view, assess the impacts over a wider geographic area, and incorporate the effect that higher electric rates would have on the overall Minnesota economy. It was Mr. Sheesley's opinion that in order to do this, the Economic Report would also have to: (1) assess the net impact on Minnesotans by weighing the positive economic impacts to northeastern Minnesota against the negative economic impacts to the rest of the state; (2) compare the impacts of alternative large energy projects; (3) consider the offsetting negative impacts of higher electricity prices; and (4) consider the economic impact of the $2 billion capital investment on the overall economy. Mr. Sheesley did not offer any specific opinions about how those four factors might affect the Project's net economic development benefits.[82]

115. In terms of potential negative economic impact, if Xcel is required to purchase 450 MW from Excelsior under the proposed PPA and make corresponding adjustments to the least-cost mix set forth in its current integrated resource plan, Xcel's rate payers will have to bear rate increases totaling between $250 million to $365 million during the Project's first year of operation, resulting in electric rate increases for Xcel customers in the range of 5.9 to 9.6 percent. The monthly bill for an average residential customer would increase approximately $5.00 to $7.50 per month, and a representative commercial or industrial customer would experience increases ranging from approximately $2,700 to $3,900 per month. However, those estimated rate impacts would decline over time as other energy sources are added.[83]

116. There will be transmission service network upgrade costs that will be required for interconnection of the Project to Xcel's system. The majority of those costs will be borne by Xcel's customers, and Xcel included those costs when it estimated the customer rate increases that would occur if it becomes obligated to purchase 450 MW of power from Excelsior under the proposed PPA.[84]

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[81] The Updated Labovitz School Report also addressed the economic impact of Mesaba Unit II, which is not being considered in this Phase I of this proceeding.
[82] XE 2030 (Sheesley Direct Testimony).
[83] XE 2038 at 6-8.
[84] *See* XE 2038 at 4-5. It appears that Mark Hervey, Xcel's analyst, converts the transmission service network and interconnection costs that Xcel's rate payers will bear into an annual revenue requirement that is built into customer rates beyond the Project's first year of operation. However, it is not completely clear from the evidence whether this is the case or whether Xcel financial analyses recognize all of those transmission service network and interconnection costs during the Project's first year of operation.

117. Minnesota Power's customers will also have to bear a portion of the transmission service network upgrade costs that will be required for interconnection.[85]

118. The payments that Xcel will be making to Excelsior for purchases of capacity and energy during the life of the PPA will be treated by credit agencies as the equivalent of long-term debt and are likely to have a negative impact on Xcel's credit rating. This will, in turn, have a negative impact on Xcel's shareholders and rate payers because it is likely to increase its cost of common equity and cost of long-term debt.[86]

119. Syngas may have other potential industrial uses other than as a fuel for generating electrical power. The Project will include a spare gasifier for increasing output and as a back-up. It is possible that that other industries with potential to use syngas may wish to locate or relocate near the Project, and that Excelsior may be able to use its spare gasifier to produce or co-generate syngas for use as a fuel, such as a transportation fuel, for production of synthetic natural gas (SNG), or as feedstock for other industrial production processes.[87] However, these other potential industrial applications of syngas cannot be relied on to make cost-competitive a project that is not independently a cost-competitive producer of electrical power.[88] In other words, it is reasonable to expect realization of the economic benefits attributable to any excess syngas Excelsior may produce only if the Project can first be established as a cost-competitive producer of electrical power.

120. Citing recent rising natural gas prices and natural gas price instability,[89] Excelsior also claims as an economic benefit that the syngas it will be producing from coal will be a low-cost, fixed price alternative to natural gas for large industrial companies within the state. However, whether syngas will, in fact, be a lower-cost, fixed price alternative to natural gas for general industrial use has yet to be established. Excelsior currently has no plans to produce syngas that will not be used in generating electrical power beyond what might be available from operating its spare, back-up gasifier.

121. In addressing the Project's economic development benefits, Excelsior suggests that by contributing to a cleaner environment, the Project's "clean coal technology" will have a favorable impact on tourism, hunting, fishing, and other outdoor activities.[90] In terms of airborne pollutants, the Project will result in reductions in comparison with older conventional coal generating facilities and, to a lesser extent, in comparison with newer SCPC generating facilities. But the Project will not be replacing any existing such facilities and thereby result in a net reduction of air pollutants emissions. Rather, it will add to existing emissions of pollutants.

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[85] XE 2025 at 12.
[86] DOC 3017 at pp.15-20.
[87] EE 1005 at 3-5.
[88] *See* NAT'L COMM'N ON ENERGY POLICY, ENDING THE ENERGY STALEMATE: A BIPARTISAN STRATEGY TO MEET AMERICA'S ENERGY CHALLENGES, pp. 52-53, cited by Excelsior at EE 1005, n. 5 at 4.
[89] EE 1005 at 7-8.
[90] EE 1005 at 8.

122. The Department assessed whether the proposed Mesaba Project would meet Minnesota's overarching energy policy goal to create and maintain a reliable, low-cost and environmentally superior electricity system. The Department identified areas where the project appeared to have potential to provide benefits to Minnesota. Specifically, the Department noted that the project was proposed to address some reliability issues that could be involved with this kind of technology. The project could also potentially result in job creation in the Iron Range region.[91]

123. In Dr. Amit's opinion, the economic benefits to the Iron Range may largely represent a redistribution of benefits within the State rather than net incremental benefits to the State. Due to the low level of unemployment in Minnesota and the Arrowhead region, it is very likely that the new construction and operation jobs would largely represent a redistribution of labor rather than a significant net increase in jobs. Moreover, to meet the future demand for electricity in Minnesota, absent the Mesaba Project, an alternative baseload proposal sited in Minnesota is likely to produce economic development benefits to the State similar to those of Mesaba. For these reasons, Dr. Amit concluded that these overall economic benefits of the Mesaba Project would be insignificant.

124. The public expressed widely divergent views on the Project at the public hearings and in written comments. Most of those views correspond with either the views of Excelsior Energy or of Xcel Energy. People living and working in northeastern Minnesota are split on whether the Project should be built. Supporters generally emphasize the expected economic benefits to the region and themselves. Opponents generally emphasize the high cost to consumers and the negative environmental impacts on the region and on their enjoyment of their homes and chosen recreation areas. Most of the public relied on evidence of impacts that was largely addressed by the parties, and gave their views of the meanings to be attached to that evidence. A few made arguments about matters not at issue in this proceeding, such as the reasonableness of various statutory provisions. Generally, the comments showed genuine, informed, and well-reasoned opinions among the public.

125. Citizens Against the Mesaba Project (CAMP) is a group of concerned citizens opposing the construction of a coal gasification power plant on the Scenic Highway in Itasca County because: 1) the plant would degrade recreational lake country near the Scenic Highway, exacerbate global warming, and pollute the air and water; 2) huge quantities of diesel fuel will be burned to mine and transport coal, to generate electricity that is not needed and which requires hundreds of miles of new transmission lines to the Twin Cities and beyond; 3) a venture with a financial risk too high for the private sector to assume should not receive in excess of $50 million in public funding and $800 million in federal loan guarantees; 4) there are only 107 permanent jobs planned for this site, many of which require higher education and specialized training, and the few jobs available for local residents do not offset the enormous environmental and financial costs; and 5) electrical transmission lines,

[91] DOC 3011 at 7-10.

railroads, roads, and pipelines for water and natural gas should not be forced on private property owners through eminent domain granted for the benefit of a private corporation. CAMP was formed in approximately June 2005, when Excelsior's preferred site for its power plant changed from an abandoned mine site near Hoyt Lakes to a pine forest and wetland near the Scenic Highway. The group produced extensive, detailed comments in opposition to the Project.

126. Several members of the public from Grand Rapids and other communities in the area expressed concern about the increased railroad traffic through their towns that would result from coal being transported to the proposed plant for processing. Several area residents discussed how train traffic cuts off the access that emergency response teams have to other parts of town or other communities on the other side of the railroad tracks. They argued that the health and safety of their residents would be adversely affected by increased train traffic.

127. Other full-time and part-time residents of the area emphasized the large amount of money taken in by Itasca County due to tourism, and discussed how their property values and communities would be negatively affected by the increased amount of pollution generated by the proposed plant. One individual referred to studies showing a direct correlation between water clarity and lakeshore property values. Many people expressed specific concern for the health and beauty of the Canisteo mine pit lake.

128. Several cities in the vicinity of the proposed plant wrote in support of the PPA. City officials in Taconite, Hoyt Lakes, Calumet, and Nashwauk support the "much-needed economic development in an environmentally friendly manner" that the Project would bring to the area. These cities see a substantial addition to the tax base, 1000 construction jobs, and over 100 permanent jobs resulting from the Mesaba Project. The Grand Rapids Area Chamber of Commerce, the Itasca County Board of Commissioners, the Itasca Economic Development Corporation, Nashwauk Public Utilities, the Range Association of Municipalities and Schools, the Western Mesabi Mine Planning Board, and the St. Louis County Board all voiced similar comments in support of the Project. Several area businesses and business owners also expressed written support for the proposed project.

129. The local trade unions also support the Project for the same reasons stated above, including the Iron Workers Local Union No. 512, Plumbers Local 34, International Brotherhood of Electrical Workers Local No. 31, Building and General Laborers Local 1091, Plumbers and Fitters Local No. 589, International Union of Operating Engineers Local Nos. 49-49E, and Heat and Frost Insulators and Asbestos Workers Local 49.

130. In sum, there are economic development benefits to the State from the Project, especially to the nearby area. There are also negative economic development impacts from the increased costs that will be passed on to business and individual ratepayers and from the negative environmental consequences of the Project. Those impacts have not been quantified. Overall, the economic development benefits weigh in

favor of the Project. But they do not justify an unreasonable price for it electric capacity and energy.

The Use of Abundant Domestic Fuel Sources

131. Minn. Stat. § 216B.1694, subd. 2(a)(7), requires the Commission to consider the use of abundant domestic fuel sources. Coal is abundant in several areas of the United States, but not in Minnesota. The PRB coal Excelsior Energy intends to buy will come from the Powder River Basin in Montana and Wyoming and the Illinois No. 6 coal will come from the Illinois Basin in Illinois, Indiana, and Kentucky.[92]

132. The terms of the proposed PPA do not expressly prevent Excelsior Energy and the Fuel Subcommittee from modifying the feedstock design specifications to use non-domestic coal. That choice would depend upon coal type efficiency and delivered price.

133. Excelsior Energy intends to obtain petroleum coke primarily from Flint Hills Resources' Pine Bend Refinery in Cottage Grove, Minnesota.[93] The crude oil refined at Pine Bend, and from which the petroleum coke is produced, comes largely or entirely from Canada. Excelsior Energy fuels expert Ralph Olson points out that many of the heavy and medium crudes that U.S. cokers are now processing are from Canada.[94] The petroleum coke for the Project is not from an abundant domestic fuel source.

134. Excelsior Energy plans to obtain natural gas from the Great Lakes Pipeline or the Northern Natural Gas Pipeline.[95] Great Lakes Pipeline delivers natural gas from Canada. The natural gas obtained there is not from an abundant domestic fuel source.

135. Thus, the Project is planning to use primarily coal from abundant domestic sources. But, when it begins operation, significant amounts of its fuel will be natural gas that is not a fuel primarily from abundant domestic sources. Moreover, nothing in the PPA expressly requires fuel from abundant domestic sources and price considerations may require changes to other sources in the future.

The Stability of the Price of the Output from the Project

136. The issues here are addressed in the Findings regarding a hedged, predictable cost beginning at Finding No. 77 above. The PPA price provisions result in a price that is subject to some adjustments and variations. While the capacity payment, once set, and O&M payments are fairly stable, the monthly fuel payment will only be so if Excelsior Energy is able to develop a portfolio of fuel and transportation agreements that provide the necessary hedges to provide that stability. The Project has more fuel

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[92] EE 1020 at 110-114 and figs. 41-43.
[93] EE 1020 at 114-115 and fig. 44.
[94] EE 1161 at 4-5.
[95] EE 1020 at 56.

flexibility than traditional coal plants, but that advantage is not particularly significant in light of the large market power possessed by the coal producers and railroads and the current and projected demand for coal and transportation. The Project and the PPA do not provide a significant price stability advantage that justifies a higher PPA price.

Potential to Contribute to Hydrogen as a Fuel

137. Minn. Stat. § 216B.1694, subd. 2(a)(7), directs the Commission to consider "the project's potential to contribute to a transition to hydrogen as a fuel resource" in making its public interest determination in connection with the PPA approval process.

138. Using hydrogen as a source of energy, particularly as a transportation fuel, is both a national and a state priority.[96]

139. According to Excelsior Energy witness Douglas Cortez, the Project's gasification technology is the only available process for converting coal to syngas, which then can be used as the primary raw material in a proven commercial technology for hydrogen production. Several gasification plants are under construction in China that will only produce hydrogen. Excelsior has no current plans to produce hydrogen, but it is technologically possible to modify its process to do so. As Mr. Cortez states,

> Although Mesaba Unit I is being designed for power generation, it is my understanding that the larger Mesaba Energy Project will encompass subsequent units that certainly could produce a large quantity of hydrogen that could potentially be the basis for a broader transition within society to using hydrogen as a fuel source.[97]

140. The hydrogen economy envisions storing energy in the form of hydrogen and then converting that hydrogen into electricity or mechanical energy when needed. That storage and conversion directly to electricity can be done by fuel cells. Fuel cells produce electricity chemically from hydrogen and the only byproduct is oxygen. Engines for vehicles and other uses can be designed to run on hydrogen and the exhaust is water vapor. Producing hydrogen is explained at one fuel cell industry site as follows:

> Almost all of the 40 million tons of hydrogen used worldwide today comes from natural gas though a process called reforming. Natural gas is made to react with steam, producing hydrogen and carbon dioxide. The hydrogen is then used to make ammonia for fertilizer, in refineries to make reformulated gasoline, and in the chemical, food and metals industries.

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[96] NAT'L COMM'N ON ENERGY POLICY, ENDING THE ENERGY STALEMATE: A BIPARTISAN STRATEGY TO MEET AMERICA'S ENERGY CHALLENGES, pp. 51, cited by Excelsior at EE 1005, Section 1, n. 5 at 4.
[97] EE 1091 at 24-25

> This is the cheapest way to make hydrogen today and is likely the way we will make hydrogen for fuel cell vehicles in the near future. Hydrogen also can be made from coal in a similar process where the coal is reacted with steam. Either way, though, the process releases carbon dioxide, a gas tied to global warming.
>
> Carbon-free methods involve splitting water into its component parts of hydrogen (H2) and oxygen (O).
>
> Electrolysis uses an electric current to separate water into hydrogen and oxygen. The electric current has to itself be produced, and the easiest but least efficient way is via some fossil fuel. The holy grail of hydrogen is to use a renewable source like solar, wind, hydro, geothermal or biomass power to create the current, making the process pollution free and sustainable.[98]

141. Mr. Cortez says that if our country is to transition to a "hydrogen economy," fossil fuels, primarily coal, will need to be used.[99] Nonetheless, the goal of producing hydrogen without producing CO_2 is in Minnesota law. Minn. Stat. § 216B.1691, sets Renewable Energy Objectives for utilities to generate or procure electricity generated from the following renewable energy sources: solar, wind, small hydroelectric, hydrogen, or biomass. Under the statute, after January 1, 2010, hydrogen used to generate electricity will only count toward a utility's Renewable Energy Objectives if it is generated from solar, wind, small hydroelectric, hydrogen, or biomass.

142. The costs and possible revenues of producing hydrogen have not been given, but the Project has the capability to be modified to produce a large quantity of hydrogen directly from coal. Thus, the Project has the potential to contribute to a transition to hydrogen as a fuel resource. But that potential will only be consistent with State goals if the Project reduces its CO_2 emissions to an acceptable level.

Comparative Emission Reductions, Including CO_2

143. In evaluating the PPA, Minn. Stat. § 216B.1694, subd. 2(7)(a), requires the Commission to consider emission reductions compared to other solid fuel baseload technologies. The comparison to be made is not restricted to the four criteria emissions Minn. Stat. § 216B.1694, subd. 1(1). The net result is to broaden the comparison to include CO_2 emissions, which all parties agree should be considered to some extent.

144. As summarized at Finding 74 above, in comparison with traditional solid fuel baseload technologies, the Project's emissions of sulfur dioxide and particulates will be significantly reduced. Its nitrogen oxides and mercury emissions will be significantly

[98] www.fuelcellsworks.com/JustthebasicsonHydrogen.
[99] EE 1091 at 24.

reduced in comparison only with older existing coal-fueled plants, but not in comparison with newer, but still "traditional," SCPC coal plants with state-of-the-art controls.

145. The MPCA compared the Project's carbon dioxide emissions with three other existing facilities and with EPA's three types of future "generic" plants. Again, the MPCA presented its comparisons as percentages by which the other actual or hypothetic facilities varied from the Project's emissions. The MPCA employed pounds of CO_2 per million BTUs as the unit of comparison:[100]

Plant	CO_2
Wabash	-9.5%
Existing PC with BACT controls	+10.3%
Desert Rock SCPC	+2.8%
SWEPCO Hempstead USC PC	+0.5%
EPA "generic" subbituminous SC	-4.2%
EPA "generic" subbituminous IGCC	-17.0%
EPA "generic" subbituminous USC	-13.3%

146. The MPCA's analysis establishes that carbon dioxide emissions from other technologies are expected to be lower than the expected carbon dioxide emissions from the Project.

147. In its Reply Brief, Excelsior Energy added three representations and warranties to Section 14.1 of the Final PPA regarding CO_2. They are:

> (H) Seller agrees to allocate the final $2 million of its Renewable Development Fund award in 2009 exclusively to fund expenditures made to refine the Mesaba Energy Project Plan for Carbon Capture and Sequestration.
>
> (I) Seller shall make a good faith effort to use the Plan for Carbon Capture and Sequestration to create a competitive proposal in response to the Department of Energy's planned Phase III solicitation for a carbon capture and sequestration demonstration project at Unit 1 of the Mesaba Energy Project.
>
> (J) Seller agrees to continue to participate as a partner in the Plains CO_2 Reduction Partnership's Phase II study in an effort to identify the optimal CCS program for the Mesaba Energy Project.[101]

148. Clean Water Action, a citizen-based environmental group with a membership of 60,000 Minnesotans, submitted public comments in opposition to the PPA agreement. Clean Water Action works for transition away from coal and nuclear

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[100] MPCA 8001, at 4-5.
[101] Ex. B (Final Proposed PPA), Section 14.1 (H)-(J).

generation toward cleaner, non-polluting sources of energy. Specifically, the group is disturbed by the fact that Excelsior is exempted from the Certificate of Need process and argues that the PPA should not be approved for a number of reasons. First, the group asserts that an increase in mercury emissions and other pollutants such as nitrogen oxide, particulate matter, and sulfur oxide are not in the public interest, and, in fact, cause acid rain, asthma, lung cancer, and cardiovascular issues, among other health conditions. Next, Clean Water Action asserts that there are other energy alternatives that are better for the environment and more reliable than coal. The group cites the Minnesota Wind Integration Study performed by and for the Minnesota Public Utilities Commission in December 2006, which concludes that "[t]he addition of wind generation to supply 15, 20, and 25% of Minnesota retail electric energy sales can be reliably accommodated by the electric power system." In addition, the Study concluded that "[t]he total integration operating cost for up to 25% wind energy delivered to Minnesota customers is less than $4.50 per MWh of wind generation." Finally, Clean Water Action contends that the PPA is not in the economic interest of the state because Xcel's rates are expected to increase 8-12% in the first year if the PPA is approved.

149. A group of 38 healthcare providers from Itasca County submitted an editorial piece to the Grand Rapids *Herald-Review* in opposition to the proposed PPA and representatives of the group testified at the public hearings.[102] The healthcare providers objected to the PPA based on the adverse health effects that would be caused by the environmental pollutants released from the Project's plants. Specifically, the group asserted that the Mesaba Energy Project would annually emit more than 440 tons of particulate matter, 1300 tons of sulfur, 2700 tons of nitrous oxides, 150 tons of volatile organic compounds, and up to 54 pounds of mercury. The group pointed to Excelsior's own data, which reveals a "measurable effect on air quality" up to 70-80 kilometers from the proposed plant. They claim the plant, by Excelsior's own data, would be responsible for 10.7 premature deaths in the United States each year with 24% of those in Minnesota, 100 people with asthma exacerbations, 791 "minor restricted activity days," and 18,313 lost work days due to illness attributed to the proposed power plant. As for the mercury emitted from the proposed plant, the group claims that the "mercury deposition impact zone" of the Project will increase the mercury levels in over 720 local lakes, affecting those eating fish caught in local lakes, particularly women of childbearing age and children. Finally, the group points to Excelsior's data predicting the cost of mortality attributable to the Project at $8.7 million per year in Minnesota and $84.9 million per year nationally. In conclusion, the Itasca County healthcare providers asked that the local business leaders and elected officials carefully consider the public health and environmental costs associated with the Mesaba Project.

150. Barry J. Hanson, author of *Energy Power Shift-Benefiting From Today's New Technologies*, raised the issue of "carbon taxes." He sites a recent survey of utility executives indicating that 85% of them think that within five years a serious penalty will be imposed by the government for putting fossil carbon into the atmosphere. Mr.

[102] Public Ex. 20 from the St. Paul public hearings on December 18, 2006.

Hanson argues that it would not be fair to push this expense onto ratepayers when cleaner alternative forms of energy are available.

151. The North Star Chapter of the Sierra Club, consisting of 24,000 members in Minnesota, also strongly objects to the proposed PPA. The Chapter is particularly concerned about Excelsior's failure to guarantee the use of carbon sequestration technology, the Project's unrealistic energy demand projections, the Project's failure to adopt the lower cost option of wind power, and the Project's environmental and economical siting costs. The North Star Chapter is most concerned that the Project is not required by the Legislature to obtain a Certificate of Need, which would require the Minnesota Public Utilities Commission to quantify the environmental costs of all means of power production while also reviewing "other external factors, including socioeconomic costs" of any proposed resource under Minn. Stat. § 216B.2422, subd. 3.

152. In summary, there is some evidence that CO_2 capture will be more possible with the IGCC technology used by the Project. The capture will theoretically be less difficult because it can be done in the syngas coming from the combustion of the coal in a gasifier. But there is some evidence that a similar process can be used on the flue gas coming from a CFB combustor, so, IGCC may have no great advantage in this regard. More importantly, Excelsior Energy does not plan to install the technology on the Project until it is required by law to do so. If and when it is, Excelsior Energy plans to install a system that removes 30% of the CO_2, and, if it is ever feasible, one that removes 90%. It is not known how those reduction levels will compare to retrofitted or other new coal-fired plants. Thus, the Project has little or no quantifiable advantage at this time over other coal burning plants and no advantage over baseload generators operating on renewables.

Ratepayer Protection from Operational Risks

153. As described by Dr. Amit, operational risks include a complete or partial shutdown of the Project or underperformance of the Project due to technical problems. Ratepayers must be assured that their payments will not be increased to pay for replacement energy and capacity in the event of a partial or complete shutdown, and ratepayers must be protected from the consequences if Xcel Energy does not meet its reserve requirements by relying on capacity that is not delivered.[103]

154. There are no limits in the PPA on the cost of fuel. The PPA requires Xcel Energy to pay for all fuel and fuel delivery costs. Excelsior Energy proposes recovering these costs directly from Xcel Energy customers through a Commission-approved variance to the fuel clause adjustment rules. Even if these costs are paid through the fuel clause and thus subject to prudence review, the PPA provides that Xcel Energy

[103] DOC 3000 at 9.

must pay all of Excelsior's fuel costs regardless of whether the Commission disallows of any of those costs.[104]

155. All risks associated with the availability and cost of fuel are shifted away from Excelsior. This arrangement might be reasonable with regard to solid fuel if it passed only prudent fuel costs on to Xcel Energy. But that is not the case here.

156. With regard to the use of natural gas, the Final PPA now places a penalty upon Excelsior Energy to give it an incentive to avoid using natural gas and reduce the cost to Xcel Energy. But Xcel Energy and its ratepayers would also pay significantly increased costs from the use of natural gas. Xcel Energy calculated that a 65% reduction of the current estimated Capacity Price would still result in a capacity payment roughly double what the capacity price is for typical gas-fired combined cycle plants.[105] That excess in the capacity payment may also be viewed as further increase to the already higher price of natural gas compared to solid fuel.

157. Under Section 8.1 of the Final PPA, the Ramp-Up Factor (RUF) is used to increase the Capacity Availability Factor, and, thus, the monthly capacity payment, particularly during the first three years of operation. The RUF is 65% during the first year of operation, 75% during the second, 85% during the third, and 96% thereafter. The RUF is divided into the preliminary availability factor that is determined by adding the proportion of total energy produced from syngas to a reduced proportion of the energy produced from natural gas. Dividing by 65% would be equivalent to a 54% bonus during the first year, 33% the second, 18% the third, and 4% thereafter. The RUF is applied regardless of actual availability. Excelsior Energy also modified the capacity payment formula in the Final PPA so that the Capacity Availability Factor can never exceed 110% of capacity, which was previously possible. After the third year, if the Project was running 100 % on solid fuel, the ongoing 96% RUF would compensate Excelsior Energy for a forecasted average of 4% in unplanned outages.[106]

158. No particular objection was made to the concept of four year ramp up period for the Project or to the numbers used for the factor, except as related to the use of natural gas. The capacity payment is the vehicle that Excelsior Energy has chosen for the downward adjustment for use of natural gas instead of solid fuel. As discussed in Findings No. 39 to 45, there is likely to be little, if any, penalty for use of natural gas for the first two or three years because of the RUF in the capacity price. The Natural Gas Factor, which is already "ramped-up" over the same time period, is diluted by the RUF. This is not consistent with Excelsior Energy's stated intent and shifts too much of the risk that the Project will not run on solid fuel to Xcel Energy and ratepayers.

159. The PPA provides for four types of Events of Default: non-curable under Section 11.1(A), 30-day curable under Section 11.1(B), one-year curable under Section 11.1(C), and 60/30-day curable under Section 11.1(D). The 30-day curable defaults

[104] Final PPA, Sections 8.3 and 10.5(C).
[105] XE 2006 at 17.
[106] Final PPA, Section 8.1; EE 1039 at 32; EE 1041 at 3; EE 1062 at 4; XE 2009 at 7.

require the payment of damages within 30 days or cure by performance that must be commenced within 30 days and diligently pursued for as long as it takes to cure the default. The one-year curable default, which is failure to achieve commercial operation within a year, allows one year to cure, plus an additional year if an independent engineer gives an opinion that commercial operation is reasonably achievable. The 60/30-day curable defaults require the payment of damages within 60 days or cure by performance that must be commenced within 30 days and diligently pursued for as long as it takes to cure the default. Section 11.2 allows the Facility Lender to step in and cure an Event of Default.

160. Section 11.5 allows the non-defaulting party to terminate the PPA if an Event of Default is not cured within the applicable cure period. Section 11.6 sets a limitation on Excelsior Energy's responsibility to pay damages upon such termination of $125/kW times the reference capacity. If the reference capacity ends up being 603 MW, damages would be limited to $75,375,000. No security is provided to ensure that this amount will be available to cover any damages that are incurred.

161. In Dr. Amit's opinion, the cure provisions are too general. There are no specific cures listed and they do not appropriately protect Xcel's ratepayers from operational risks.[107] He is correct. Moreover, the ability to commence and "diligently pursue" a cure is too open-ended and difficult to enforce. The default cures provide very limited protection to Xcel Energy and ratepayers.

162. Dr. Amit estimated if the PPA was terminated, replacement capacity and energy could cost $15/MWh more than under the PPA. For a year that would total about $71,505,000, almost as much as the damages limit.[108] Xcel Energy witness John J. Reed called the damages limit "far below an acceptable level and well outside the bounds of commercial reasonableness or industry norms."[109] The damages limitation is unreasonably low and is an unreasonable allocation of operational risks to Xcel Energy's ratepayers.

163. The default provisions of the PPA do not appropriately allocate operational risks of the PPA between Excelsior Energy and Xcel Energy and its ratepayers.

164. Under the Final PPA, the variable and fixed O&M costs will both be adjusted annually by the implicit price deflator for the gross domestic product and are also subject to change every five years. Therefore, Xcel Energy's ratepayers bear full responsibility for the inflation risk and for the risk of increased O&M costs every five years. This risk allocation is unreasonable because such open-ended provisions lack any financial incentive or discipline for Excelsior Energy to minimize variable and fixed

[107] DOC 3000 at 14.
[108] DOC 3010 at 14.
[109] XE 2017 at 16.

O&M costs and do not protect Xcel Energy's ratepayers from inappropriate expenditures. Excelsior Energy should bear an equal or greater share of this risk.[110]

165. The Final PPA shifts significant operational risks onto Xcel Energy and its ratepayers that should be borne by Excelsior Energy.

Ratepayer Protection from Financial Risks

166. Typically, the developer of a plant to be built for the sale of energy under a contract bears the risks for the successful completion of the project on time and on budget. The project developer bears these risks because it is the party that controls the activities related to the completion of the project on time and on budget, and therefore is in the best position to mitigate the risks through contracts with the EPC contractor, investors, equipment vendors, and other participants.[111]

167. In this case, Excelsior Energy is seeking approval of the Final PPA before the EPC cost for the Project is determined. The Final PPA states an estimated trade secret target EPC contract cost (TECC). The Final EPC Contract Cost (FECC) will be determined in negotiations with contractors. Neither the TECC nor the FECC were or are subject to any requirement for competitive bidding, price caps, or any prudency review by Xcel Energy, the Commission, or any other entity.[112]

168. Excelsior Energy added a provision to Schedule I of the Final PPA giving the Commission conditional limited power to review a cost increase in the FECC over the TECC. It states:

> [If the FECC exceeds the TECC by a certain percentage], then the MPUC must separately approve the adjustment to the Capacity Price, based on a determination that the adjustment is reasonable taking into account price escalations that have occurred in the construction markets since December 18, 2005, and taking into account the relative price increases that would have also impacted other solid-fuel baseload resources.

This is only a review of the increase in the cost from the TECC to the FECC to see if it is consistent with cost increases in the construction market over the same time period. It does not provide for any type of review of the cost of the Final EPC Contract or the reasonableness of cost increases in the construction market. It does not provide for any meaningful opportunity to halt the Project if the costs or cost increases are excessive. It does not provide any meaningful ratepayer protection from the risk of increases in the EPC contract price or the Capacity Payment.

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[110] DOC 3014 at 12-13.
[111] XE 2017 at 7-8.
[112] Final PPA, Section 6.2, Ex. G, and Schedule I.

169. Excelsior's cost estimates for the TECC were made using third-quarter 2005 data. The costs for coal power plants have risen since that time. Big Stone II updated their third-quarter 2005 cost estimate for plant construction based on 2006 data and found an increased plant cost of approximately 25% per MWh.[113] It is likely that the Project's EPC cost will increase significantly.

170. The EPC contract is projected to be finalized by February 2008, but it could extend to February 2010 or 2012. The PPA provides that at that time, the final Capacity Price will be adjusted to include any increase in the cost of capital as reflected by the U.S. Treasury Index. Thus, the financing cost risk is shifted to ratepayers by making the interest rate component a flow through in the PPA.

171. As with any large development of this nature, there is a risk that Excelsior Energy may run into financial difficulties during the construction period or early years of operation leading to reorganization or liquidation. The proposed PPA does not have the protections typical in other PPAs for the protection of the buyer under these circumstances: Such protections include a security fund to allow the buyer a ready source of funds if such a default occurs; a subordinated lien on the facility to assist the buyer if the project becomes financially distressed; and step-in rights allowing the buyer to take over the plant if the developer fails to keep construction on track.[114] The risk of the Project's financial failure should be borne by Excelsior Energy, not Xcel Energy's ratepayers.

172. The Final PPA does not reasonably protect Xcel Energy's ratepayers from the financial risks of the PPA.

Impacts on Xcel Energy's Financial Health

173. The PPA will also create indirect costs for Xcel Energy. The indirect costs include costs that Xcel Energy will incur outside of the PPA and impacts upon Xcel Energy's financial health.[115]

174. The proposed PPA requires Xcel Energy to make monthly capacity payments for a 25-year period. Credit rating agencies consider such payments to be equivalent to long-term debt and adjust the company's credit rating to reflect such obligations. Investors adjust their risk valuation of the Company accordingly. For example, Standard and Poor's applies a 30 percent adjustment factor to Xcel Energy (i.e., 30 percent of Xcel Energy's Net Present Value obligations are converted into long-term debt). The PPA debt equivalent based on the S&P methodology is approximately $1.9 billion. Based on Xcel Energy's last rate case (Docket No. E002/GR-05-1428), its projected 2006 long-term debt is approximately $1.19 billion. Therefore, the imputed long-term debt from the PPA would double Xcel Energy's long-term debt obligations. In Dr. Amit's opinion, Xcel Energy's capital structure including the proposed PPA's

[113] DOC 3010 at 25.
[114] XE 2006 at 28; DOC 3010 at 17-18.
[115] DOC 3014 at 16.

imputed debt and resulting financial ratios, may result in a credit rating of BB for Xcel Energy. That is considered speculative and would have serious financial effects on Xcel Energy and its ratepayers. The lower credit rating and higher financial risk would also significantly increase Xcel Energy's cost of long-term debt, cost of common equity, and overall cost of capital.[116]

175. In the Department's analysis of Xcel Energy's 2004 resource plan, Docket No. E002/RP-04-1752, the Department concluded that Xcel Energy will need additional baseload of 375 MW in 2015 and 2017, respectively. For the years 2011 through 2014, the average price of the PPA is $110.80/MWh.[117] This price is significantly higher than the projected price of energy and capacity that may be displaced by the PPA's contracted energy and capacity according to Xcel Energy's IRP information. Therefore, for the years 2011 through 2014, the PPA would impose extra costs on Xcel's ratepayers as they will start paying for energy at a high price even though they do not need the energy until 2015. This cost would be at least an additional $30.80/MWh over the period 2011-2014.[118]

176. A significant number of retired Minnesota natives residing all around the state and living on fixed incomes objected to the proposed PPA. Many of these individuals are Xcel Energy shareholders who count on dividends from these holdings to pay their monthly bills. They expressed concern that the proposed PPA between Excelsior and Xcel would decrease the dividends from their Xcel stock holdings and increase the rates on their energy bills. Many of these individuals did not think it was fair to force Xcel to sign an agreement for power that the company claims it does not need.

177. The Minnesota Utility Investors (MUI), a grassroots organization of almost 27,000 utility shareholders, submitted materials in opposition to the proposed PPA. MUI members have two roles in Minnesota's energy market, as investors in utilities and as consumers of electricity and natural gas. Many of the members are retirees living on a fixed income and relying upon the utility dividends to supplement their livelihood, as discussed above. MUI argues that Xcel does not need the amount of power required by the proposed PPA and that Xcel recently announced their plan to backup their baseload need of 375 MW by 2015 with wind energy and hydro power from Manitoba Hydro. MUI also contends that any positive economic impact that the proposed PPA has on the Iron Range will be outweighed by the negative effect (increased power rates) on the rest of the state. The group further claims that any environmental benefits of the IGCC technology are negligible when compared to modern super critical pulverized coal performance; the group also points out that the Project does not include a plan to capture carbon dioxide. Another concern of MUI is the transmission of the power generated by the Project from the Range to the place it will be utilized. MUI members are concerned that they, as shareholders in local power companies, will be responsible

[116] DOC 3014 at 18-19.
[117] DOC 3010 at 29-30.
[118] DOC 3000 at 30.

for the cost of the upgrades necessary to facilitate the transmission of the power from one place to another. In addition, MUI is concerned about the size of the proposed plant and that a 600 MW plant has never been built in the United States. MUI members worry that Xcel's credit rating will be damaged by the scope and size of the proposed Project, thereby reducing the value of the company.

178. The PPA would have significant negative affect upon Xcel Energy's financial health.

Reasonableness of the Cost of the PPA

179. The reasonableness of the cost of the PPA can be ascertained by comparing the PPA costs to alternative baseload facilities of similar sizes. If the prices of the PPA are lower or similar to the prices of energy and capacity of the alternative baseload facilities one can conclude that the PPA's prices are reasonable.[119]

180. Department witness Eilon Amit compared the prices the PPA with those of Big Stone II, Comanche Unit 3 (an Xcel Energy plant in Colorado), and Sherco 4.[120] Dr. Amit calculated the average annual and levelized prices of the PPA for Excelsior's two alternative sites.

Table 1: Cost (Price) Comparison Including Emission Costs, Excluding Transmission Costs

Alternative	Average Annual Price ($/MWh)	Levelized Price ($/MWh)
Excelsior		
West Site (603 MW)	$104.33	$ 96.04
East Site (598 MW)	$114.25	$104.91
Big Stone II Supercritical	$ 81.91	$ 73.02
Sherco 4 Supercritical	$ 74.90	$ 72.54[121]

Dr. Amit also calculated the prices for a 450 MW PPA at both sites in case the Commission determines that value in the IEP Statute is mandatory and cannot be modified by the Commission. Those prices are about 25 percent higher than the prices shown for full capacity PPAs at the two possible sites.

181. Before the MISO had determined what transmission upgrades would be required to connect the Project to the transmission grid, Dr. Amit made following estimates of the PPA's costs including transmission:

[119] DOC 3000 at 21.
[120] DOC 3000 at 21-27; DOC 3018 at 3; DOC 3020.
[121] DOC 3023 at 3. The Comanche 3 estimated price is trade secret and has not been restated here. It is available in the nonpublic versions of the cited exhibits. It is not greater than the Big Stone II price.

Table 1: Cost (Price) Comparison Including Emission and Transmission Costs

Alternatives	Levelized Price With Emissions, No Transmission Cost $/MWh	Levelized Transmission $/MWh	Total Levelized Costs $/MWh
Excelsior Energy			
West Site (603 MW)	96.04	9.21	105.25
East Site (598 MW)	104.91	9.21	114.12
Big Stone II	73.02	2.74	75.76
Sherco 4	72.54	2.79	75.33[122]

182. Subsequently, Excelsior Energy was allowed to file a determination from the MISO that fewer transmission upgrades would be necessary to connect either site to the transmission grid than originally anticipated, reducing the estimated cost from $180 million to $50 million, in 2006 dollars. Based upon this new information, Dr. Amit revised his levelized transmission cost figures from $9.21/MWh down to $2.58/MWh.[123] That change reduces his total levelized cost estimates for the West and East Sites. It would cause Table 1 to be revised as follows:

Table 2: Cost (Price) Comparison Including Emission and Transmission Costs

Alternatives	Levelized Price With Emissions, No Transmission Cost $/MWh	Levelized Transmission $/MWh	Total Levelized Costs $/MWh
Excelsior Energy			
West Site (603 MW)	96.04	2.58	98.62
East Site (598 MW)	104.91	2.58	107.49
Big Stone II	73.02	2.74	75.76
Sherco 4	72.54	2.79	75.33[124]

183. The levelized costs calculated by Dr. Amit provide a reasonable basis for comparison. They demonstrate that a PPA for the Project's preferred West Site would cost Xcel Energy and its ratepayers about 30 percent more than capacity and electricity from other comparable sources.

184. Excelsior Energy plans to configure Units I and II to allow for the installation of additional equipment that can capture up to 30% of the potential carbon in its selected feedstock possibly as early as 2014, with the possibility of adding a longer term option later for up to 90% removal, if and when DOE demonstrates such the feasibility of such removal. However, it would install the additional equipment only if it is required by law. Excelsior Energy would expect the Final PPA to be amended to allow it to be compensated at a reasonable cost of capital for its investments and to be made whole on all other costs associated with the its carbon capture and sequestration plan (CCS Plan).[125]

185. Based on information provided by Excelsior and analyzed by the Department, the cost of equipment needed to capture some CO_2 at the Project is

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[122] DOC 3018 at 3, corrected in DOC 3024 at 1.
[123] DOC Reply Brief at 23-24.
[124] The DOC Reply Brief computed different numbers than shown in this table.
[125] EE 1067 at 1-2.

approximately $472.3 million in 2011 dollars. The cost of a pipeline necessary to transport captured CO_2 from the plant to depleted petroleum wells in Alberta, Canada, where it could possibly be used to enhance additional oil production and be stored, is approximately $635.4 million in 2011 dollars. Therefore, the total estimated cost to capture and sequester CO_2 would be $1.1077 billion in 2011 dollars.[126] From that data, Dr. Amit estimated the levelized cost of the additional equipment needed to capture CO_2 and the pipeline to transport it to the nearest site for geological storage at an additional $50.02 MWh for either of the proposed sites.

186. As Dr. Amit states, "After accounting for transmission costs, AFUDC costs and sequestration costs, the least cost of Excelsior plants (West Site 603 MW) is significantly more expensive than any of the alternative baseload plants."[127] If anything, the cost estimates for the Project are low; they will quite likely exceed the cost of comparable sources by even more than 30 percent.

187. An additional cost associated with carbon capture is the reduced operational efficiency of the Project. Excelsior Energy suggests that capture of 30% of the carbon produced by the Project will result in at least a ten percent loss of plant efficiency.[128] Thus, the revised cost of the Project with carbon capture ability would be divided over significantly lower capacity and output, resulting in significantly greater payments by Xcel Energy and its ratepayers for the energy provided.

188. In light of the foregoing, the Final PPA is not in the public interest as required by Minn. Stat. § 216B.1694, subd. 2(a)(7). Because the major defect in the PPA is the unreasonableness of the price charged to Xcel Energy, it is not possible to amend the PPA to make it reasonable. It is very unlikely that Excelsior Energy can agree to a lower price.

The CET Statute, Minn. Stat. § 216B.1693

189. Again, Minn. Stat. § 216B.1693, provides that if the Commission finds that a Clean Energy Technology is or is likely to be a least-cost resource, Xcel Energy must supply at least two percent of the electric energy it provides to retail customers from Clean Energy Technology. It also provides that such electric energy must be supplied by the Innovative Energy Project defined in Minn. Stat. § 216B.1694, subd. 1, unless the Commission finds doing so contrary to the public interest.

190. Two percent of the electric energy Xcel Energy provides to retail customers today may be about 180 MW.[129]

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[126] DOC 3014 at 21.
[127] DOC 3018 at 3.
[128] EE 1091 at 20; MCGP 5000 at 8.
[129] Xcel Energy's Proposed Findings of Fact, Finding No. 13. There appears to have been no evidence tendered as to what two percent of Xcel's retail load is. Xcel Energy's Proposed Findings state that it is 180 MW, without citation. Administrative notice has been taken that the Monticello Generating Plant has a capacity of 600 MW, which is about ten percent of Xcel's retail load. See Finding No. 18. If that is
(Footnote Continued on Next Page)

191. Minn. Stat. § 216B.1693 expires January 1, 2012. That would be about the time the Project comes on line. No party has raised an issue regarding the expiration of the statute and we do not address it here.

192. "Clean Energy Technology" is defined in Minn. Stat. § 216B.1693(c). As found in Finding No. 96, the three-part test in Minn. Stat. § 216B.1693(c) is identical to the three-part test in Minn. Stat. § 216B.1694, subd. 1(1), which comprises one of the three requirements to be an Innovative Energy Project.

193. As found in Findings Nos. 33 to 75 and 97, the Project does not, in comparison to traditional coal technologies, significantly reduce emissions of two of the four pollutants required to be significantly reduced by Minn. Stat. § 216B.1693(c). Therefore, the Project and the technology it uses do not meet the requirements of Stat. § 216B.1693(c) to be considered a "Clean Energy Technology."

194. If it is determined that the Project and the technology it uses meet the requirements of Stat. § 216B.1693(c) to be considered a "Clean Energy Technology," the following Findings apply.

195. Excelsior is only proposing that 450 MW of its proposed PPA be reviewed under Minn. Stat.§ 216B.1694. It proposes that the proposed PPA's other 153 MW (West Range Site) or 148 MW (East Range Site) be reviewed and approved pursuant to Minn. Stat. § 216B.1693, the Clean Energy Technology statute.[130] It is most appropriate to determine cost and pricing on a per Megawatt-hour basis. In order to do so, the costs of the Project should be determined on the total cost and total output of the Project.

196. As found above beginning at Finding No. 179, the costs of the PPA for either proposed site are much higher than the costs for comparable alternatives. Therefore, the Project and its technology are not a least-cost resource within the meaning of Minn. Stat. § 216B.1693.

197. Based on its analyses and the entire record, the Department concluded that the PPA as proposed is not likely to be a least-cost resource and is not in the best interests of the public as required by Minn. Stat. § 216B.1693. The Department is correct.

198. All findings of fact more appropriately construed as conclusions of law are adopted as such and all conclusions of law more appropriately construed as findings of fact are adopted as such.

(Footnote Continued From Previous Page)
correct, two percent would be about 120 MW. Excelsior Energy is seeking approximately 153 MW under the CET Statute, apparently because that is its design capacity, 603 MW, less the 450 MW it is seeking under the IEP statute.

[130] Order on Motion for Summary Disposition of Xcel Industrial Intervenors at 7.

Based on these Findings of Fact, and for reasons set forth in the following Memorandum, the Administrative Law Judges make the following:

CONCLUSIONS OF LAW

1. The Minnesota Public Utilities Commission and the Administrative Law Judges have jurisdiction over this matter pursuant to Minn. Stat. §§ 216B.08, 216B.1693, 216B.1694, and 14.50, Minn. R. 1400.5100-.8400, and to the extent not superseded by those rules, Minn. R. 7829.0100-.3200.

2. The Commission gave proper notice of the hearing in this matter, has fulfilled all relevant substantive and procedural requirements of law or rule, and has the authority to take the action proposed.

3. The IEP Statute permits the Commission to amend or modify the initial PPA to raise or lower the amount of the Project's statutory power sale entitlement.

4. The Project does not satisfy the first prong of the definition of an Innovative Energy Project under Minn. Stat. § 216B.1694, subd. 1(1), because the Final PPA does not assure that coal will be used as the primary fuel and because it has not been established that the Project significantly reduces all of the statutorily identified emissions in comparison to traditional technologies.

5. The Project satisfies the second prong of definition of an Innovative Energy Project under Minn. Stat. § 216B.1694, subd. 1(2), because it is capable of offering a long-term supply contract at a hedged, predictable cost.

6. Since the Project fails to meet the requirements of Minn. Stat. § 216B.1694, subd. 1(1), it is not an "Innovative Energy Project" for purposes of Minn. Stat. § 216B.1694.

7. Since the Project is not an Innovative Energy Project, it does not qualify under Minn. Stat. § 216B.1694, subd. 2(a)(4), as a "Clean Energy Technology" as defined in section 216B.1693.

8. The Final PPA is not in the public interest as required by Minn. Stat. § 216B.1694, subd. 2(a)(7).

9. The Final PPA should not be approved, primarily because of its unreasonable cost to Xcel Energy and its ratepayers, the likelihood that its cost will increase, not decrease over time, and because of the other deficiencies identified in the Findings. While Excelsior Energy and its witnesses have claimed that the PPA cost will become more reasonable in the future, particularly in light of the Project's environmental benefits, there is not sufficient evidence of that value to overcome the very significant cost difference that exists today.

10. The Project and its technology do not meet the definition of a Clean Energy Technology under Minn. Stat. §216B.1693(c) because they do not significantly reduce all the statutorily identified emissions in comparison to traditional technologies.

11. The Project and its technology do not satisfy the requirements of Minn. Stat. § 216B.1693(a) because the Final PPA is not, and is not likely to be, a least cost resource including the costs of ancillary services and other necessary generation and transmission upgrades.

12. It would be contrary to the public interest for the Project to supply at least two percent of Xcel Energy's retail load starting in 2012.

Based on the foregoing Conclusions, and for reasons set forth in the following Memorandum, the Administrative Law Judges make the following:

RECOMMENDATION

IT IS HEREBY RESPECTFULLY RECOMMENDED that the Public Utilities Commission order:

1. That Excelsior Energy's Petition asking the Commission to approve, amend, or modify the terms and conditions of the Final PPA under Minn. Stat. § 216B.1694 be **DENIED** and that the Final PPA be **DISAPPROVED**.

2. That if the Commission approves the Final PPA, that it first be amended through negotiations among Excelsior Energy, Xcel Energy, and the Department to address the deficiencies identified in this Report, then returned to the Commission for final approval.

3. That Excelsior Energy's Petition asking the Commission to determine under Minn. Stat. § 216B.1693 that the Project and its IGCC technology is, or is likely to be, a least-cost resource, thus obligating Xcel Energy to use the plant's generation for at least two percent of the energy supplied to its retail customers, be **DENIED**.

4. That Excelsior Energy's Petition asking the Commission to determine that, under the terms of Minn. Stat. § 216B.1693, at least 13 percent of the energy supplied to Xcel Energy's retail customers should come from the Units I and II of the Mesaba Energy Project by 2013 be considered in Phase 2 of this matter.

Dated: April 12, 2007

<u>/s/ Steve M. Mihalchick</u>
STEVE M. MIHALCHICK
Administrative Law Judge

<u>/s/ Bruce H. Johnson</u>
BRUCE H. JOHNSON
Administrative Law Judge

MEMORANDUM

Applicable Law and General Legislative Intent

The Legislature enacted both the Clean Energy Technology Statute, Minn. Stat. § 216B.1693, (sometimes CET Statute) and the Innovative Energy Statute, Minn. Stat. § 216B.1694, (sometimes IEP Statute) in its 2003 Special Legislative Session as part of what is commonly referred to as the 2003 Omnibus Energy Bill. Other provisions of that Act dealt with radioactive waste management, renewable energy development, disconnection of residential customers, and various other topics related only by their connection with the general topic of energy.[131]

Construction of a statute is a question of law, which must be determined in the first instance by the decision-making administrative tribunal but which may be determined *de novo* by a reviewing court.[132] Therefore, legal opinions that offer legal analysis of a statute or an analysis of how a statute should be applied to the facts are not considered evidence because they serve no useful purpose in the fact-finding process.[133] Rather, any legal opinions about how the CET and IEP statutes should be construed that parties have offered in this proceeding will be considered as legal argument and not as evidence.

"[I]f the words of the statute are 'clear and free from all ambiguity,' further construction is neither necessary nor permitted."[134] One simply gives it effect according to the meaning of its plain language.[135] When it becomes necessary to construe an ambiguous statute, the goal "is to ascertain and effectuate the intention of the Legislature."[136] One "may ascertain the Legislature's intent by considering a number of matters, including the legislative history, the necessity for the law, and the consequences of various interpretations."[137] One can also apply one or more of the traditional canons of statutory construction.[138]

However, apart from language of the bill that resulted in the enactment of the Minn. Stat. §§ 216B.1693 and 1694,[139] the language of the Act that was passed and signed into law,[140] and the language of the statutes, as codified in Minnesota Statutes,

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[131] Act of May 29, 2003, ch. 11; 2003 Minn. Laws 1st Spec. Sess. 1661.
[132] *Hibbing Education Association v. Public Employment Relations Board*, 369 N.W.2d 527, 529 (Minn. 1985).
[133] *Conover v. Northern States Power Co.*, 313 N.W.2d 397, 402-03 (Minn. 1981), citing the Committee Comment to Minn. R. Evid. 704.
[134] *Owens v. Water Gremlin Co*., 605 N.W.2d 733, 736; (Minn. 2000)
[135] *In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. § 216B.1691*, 700 N.W.2d 533, 536 (Minn. App. 2005).
[136] Minn. Stat. § 645.16 (2006).
[137] *Burkstrand v. Burkstrand*, 632 N.W.2d 206, 210 (Minn. 2001).
[138] *Gomon v. Northland Family Physicians, Ltd*., 645 N.W.2d 413, 416 (Minn. 2002)
[139] H.F. 9, 83rd Leg., 1st Spec. Sess. (2003).
[140] Act of May 29, 2003, ch. 11, art. 4, 2003 Minn. Laws 1st Spec. Sess. 1661.

the record of this proceeding contains no legislative history.[141] The record does contain some more recent statements by legislators, including some bill authors, as to what the Legislature intended. However, comments and statements of legislators, including authors, *made after a statute has been passed* "are inadmissible for the purpose of construing a statute."[142] That does not mean that more recent statements by legislators are irrelevant. But it means that, as a matter of law, those more current statements are more in the nature of public comments than evidence of legislative intent. In any event, even if those more recent legislative statements were admissible to ascertain the meaning of ambiguous provisions of the CET and IEP statutes, statements of legislative intent "may not be used to create an ambiguity"[143] nor "to impeach the text of an enrolled bill."[144]

The necessity or purpose of a statute may be considered in determining the meaning of an ambiguous provision.[145] One readily apparent legislative purpose in enacting Minn. Stat. §§ 216B.1693 and 1694 was to encourage the development of highly efficient combined-cycle generation technology using coal as a primary fuel (IGCC technology) as a goal for the State of Minnesota. Thus, the terms of some provisions in the two statutes may be so closely related "as to require they be interpreted in light of one another"— in other words, be read in *pari materia*.[146] However, to some extent the two statutes accomplish the same legislative policy in different ways. Therefore, it may not be appropriate to construe some provisions of the two statutes *in pari materia*.

On the other hand, statutory provisions set in other articles of the 2003 Omnibus Energy Bill cannot be read *pari material* with Minn. Stat. §§ 216B.1693 and 216B.1694 because those other statutory provisions have distinctly different statutory purposes and their subjects are prima facie unrelated to the subject of the CET and IEP statutes.[147]

[141] The substantive provisions of the bill, the Act, and the statutes, as codified, are all identical and provide no further insight into legislative intent.
[142] *Krueth v. Independent School District No. 38*, 496 N.W.2d 829, 834 (Minn. App. 1993). The logic behind the principle is that the political environment changes from session to session and from year to year. What the Legislature's current intent with regard to the meaning of a statute can be materially different from what the Legislature's intent may have been in 2003 at the time the statutes were enacted.
[143] *Nevels v. State of Minnesota Department of Human Services*, 590 N.W.2d 798, 802 (Minn. App. 1999).
[144] *Washington County v. AFSCME, Council No. 91*, 262 N.W.2d 163, 167 (Minn. 1978).
[145] *Burkstrand v. Burkstrand*, *supra*, 632 N.W.2d at 210.
[146] *State v. McKown*, 475 N.W.2d 63, 66 (Minn. 1991).
[147] Excelsior suggests that the potential obligations placed on Xcel in the CET and IEP statutes were the legislative price that Xcel had to pay for passage of radioactive waste management provisions in art. 1 that were favorable to Xcel. There is no evidence in the record of legislative history establishing that, and the fact that the two sets of provisions were in the same ominibus bill does not require that they be read *in pari materia*. Under Minn. Const. art. IV, §17, "the common thread" that connects the subject matter of provisions in an omnibus bill may be, at most, "a mere filament." *Associated Builders and Contractors v. Ventura*, 610 N.W.2d 293,302 (Minn. 2000). On their face, the CET and IEP provisions in art. 4 of the act are no more connected with the radioactive waste management provisions in art. 1 than are the disconnection of residential customers provisions in art. 3.

Interpreting the IEP Statute, Minn. Stat. § 216B.1694

The IEP statute generally requires the Commission to make two separate, but related determinations: (1) whether Excelsior's Project qualifies as an "Innovative Energy Project," within the meaning of Minn. Stat. § 216B.1694, subd. 1; and (2) if so, what are the appropriate terms under which Excelsior is entitled to enter into a PPA pursuant to Minn. Stat. § 216B.1694, subd. 2(a)(7). There is ambiguous language in both statutory provisions that requires interpretation.

Interpreting Minn. Stat. § 216B.1694, subd. 1

Excelsior suggest that the Legislature has already made a legislative finding of fact that Excelsior's Mesaba Project is an "Innovative Energy Technology" within the meaning of the IEP and CET statutes, and that it is therefore unnecessary for the Commission to make any findings or conclusions in that regard. But if that were the case, it would have been unnecessary for the Legislature even to have set forth the criteria for an Innovative Energy Project in Minn. Stat. § 216B.1694, subd. 1. It could simply have enacted a legislative finding of fact in the statute determine that the Mesaba Project is an Innovative Energy Project, thereby eliminating the need to include a subdivision 1 in the statute.

Excelsior suggests that the fact that the Notice of Hearing failed to specifically identify as an issue whether Excelsior meets the statutory qualifications for an "Innovative Energy Project" that are set forth in Minn. Stat. § 216B.1694 represents a prior finding by the Commission that Excelsior does meet those qualifications. Excelsior therefore argues that its status as an innovative technology project need not be considered in this proceeding.[148] The first issue that the Commission set forth in the Notice of Hearing is whether the Commission should "approve, amend, or modify the terms and conditions of a proposed power purchase agreement." Answering that question necessarily involves an inquiry into whether Excelsior's Project qualifies as an Innovative Energy Project (hereafter sometimes IEP) and is therefore entitled to enter into a PPA, and the Commission recognized that the issues it specifically addressed in the Notice of Hearing involved "numerous sub-issues." Second, the Commission referred "all issues" to the Office of Administrative Hearings. Finally, the Notice of Hearing also specifically states that parties "may also raise and address other issues relevant to the petition." Therefore, whether Excelsior's Project qualifies as an Innovative Energy Project, within the meaning of Minn. Stat. § 216B.1694, subd. 1, is an issue to be addressed in this proceeding.

Interpreting Minn. Stat. § 216B.1694, subd. 1(1)

Minn. Stat. § 216B.1694, subd. 1(1), requires that the Project result in "significantly reduced sulfur dioxide, nitrogen oxide, particulate, and mercury emissions from those of traditional technologies." That language contains three ambiguities. First,

[148] Initial Brief of Excelsior Energy, Inc. (hereafter Initial Excelsior Brief) at 10.

the Commission must determine whether use of the Project's technology results in "*significantly* reduced sulfur dioxide, nitrogen oxide, particulate, and mercury emissions from those of *traditional* technologies." The statute itself neither defines "significant" nor refers to any objective standards for determining whether potential emissions reductions will be "significant." In a situation like this, where the statute lacks objective standards for arriving at a highly technical conclusion, one presumes that the Legislature intended the Commission to establish the criteria and standards for implementing the statutory test. Where the Legislature has committed that function to agency discretion,[149] the law simply requires that the criteria and standards the agency fashions be "reasonable and further the purpose of the statute."[150]

Second, what the Legislature meant by the term "traditional technologies" in Minn. Stat. § 216B.1694, subd. 1(1), is not completely clear. The specific question that must be addressed here is whether the Project's emissions should be compared to those of SCPC plants. The intervenors generally argue that Minn. Stat. §§ 216B.1693 and 1694 both require an emissions comparison between the Project's proposed IGCC plant and SCPC plants. However, such a comparison is required only if SCPC technology meets the definition of "traditional." Again, the Legislature did not enact any criteria or standards for determining which solid fuel technologies are "traditional" and which are not. Thus, it must be presumed that the Legislature intended for the Commission to employ its expertise in fashioning the appropriate criteria or standards for determining whether SCPC technologies are "traditional." [151]

As used in this context, the word "traditional" means a practice that has been in effect over an extended period of time.[152] Creating power by burning coal to create steam to drive turbine generators is a process that has been in existence for many years and therefore represents a "traditional" way of producing power. Pulverizing coal and burning it to create steam at "supercritical" temperatures is a technology that has been in existence since the 1950s. That technology does not fundamentally alter the process by which the power is produced; it merely makes the process more efficient and results in the production of fewer pollutants. On the other hand, IGCC technology does fundamentally alter the process by which the power was produced. Thus, SCPC technology does meet the definition of a "traditional" solid fuel technology and the Project's emissions should be compared to those of SCPC plants. This reading is most consistent with the IEP and CET Statutes' promotion of a less polluting use of coal to generate electricity.

The final potential ambiguity in involves the language "… significantly reduced sulfur dioxide, nitrogen oxide, particulate, and mercury emission from those of traditional technologies." The question is whether the Legislature intended the phrase "significantly reduced" to apply to each of the four subsequently specified emissions—

[149] *Id.* at 726.
[150] *Id*.
[151] *See In re Application of Northwestern Bell Telephone Co.*, *supra*, 386 N.W.2d at 726.
[152] As used in this statutory context, "traditional" means pertaining to "[a] time-honored practice or set of practices." AMERICAN HERITAGE DICTIONARY (2nd College Ed. 1985).

i.e., sulfur dioxide, nitrogen oxide, particulate, and mercury"—or to the combination of them in the aggregate. The rule of last antecedent provides that when a series of words is followed by a modifier, the modifier only applies to the last item in the list.[153] A necessary corollary is that when a series of words is preceded by a modifier, the modifier applies to all words in the list. In other words, the Legislature intended there to be a demonstration that each of the specified emissions be significantly reduced.

Interpreting Minn. Stat. § 216B.1694, subd. 1(2)

Minn. Stat. § 216B.1694, subd. 1(2) contains yet another requirement for an Innovative Energy Project that is somewhat similar to the requirement in Minn. Stat. § 216B.1694, subd. 1(3)—namely, "that the project developer or owner [certify that the project be] capable of offering a long-term supply contract at a hedged, predictable cost." Excelsior first argues that, like the Commissioner's designation in Minn. Stat. § 216B.1694, subd. 1(3), the Legislature is not requiring that Excelsior establish that its Project actually be "capable of offering a long-term supply contract at a hedged, predictable cost." Rather, Excelsior contends that the Legislature is only requiring "that an IEP have a *certification* by the Project owner or developer – albeit, a certification to that effect."[154] Thus, Excelsior argues that the question presented in determining whether the Mesaba Project meets the definition of an IEP is only whether or not it has made the required certification. Excelsior has, in fact, made that certification.[155] However, the Legislature intended there to be material differences in the relative status of the IRR Commissioner's designation under subdivision 1(3) and Excelsior's certification under subdivision 1(2).

First of all, the nature of the act required by Minn. Stat. § 216B.1694, subd. 1, paragraphs (2) is fundamentally different from the act required by paragraph (3). "Certify" involves the act of formally confirming in writing that something is true or accurate;[156] in other words, the act of certification necessarily involves an assertion about the truth value of what is being certified. On the other hand, "designation" means pointing out the location of something for a specific purpose.[157] In other words, a designation does not necessarily involve an assertion about the truth value of what is being designated. Second, the nature of the actors identified in paragraphs (2) and (3) is also fundamentally different. Paragraph (3) involves an official determination by the head of a coordinate state agency for the purpose of carrying out a statutory duty. As noted above, the Commission lacks the requisite statutory authority to conduct an administrative review of its sufficiency. On the other hand, Minn. Stat. § 216B.1694, subd. 1(2) requires something other than an official designation, it requires a "certification" by a private party who is seeking a government benefit in a proceeding

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[153] REVISOR OF STATUTES, MINNESOTA REVISOR'S MANUAL (2002) at § 10.13(b).
[154] Excelsior's proposed Findings of Fact, Conclusions of Law, and Recommendation at ¶¶ 99 through 102.
[155] EE1002.
[156] In the sense germane to this context, "certify" means "to confirm formally as true, accurate, or genuine, esp. in writing." AMERICAN HERITAGE DICTIONARY (2nd College Ed. 1985).
[157] *Id.*

that is properly before the Commission. Moreover, one of the Legislature's primary purposes in creating the Commission was to create an agency that would assess the impact of actions taken by public utilities on the citizens of Minnesota, including rate payers.[158] To conclude that the Commission lacks the authority to look beneath Excelsior's certification to determine the truth value of what Excelsior is asserting would ignore one of the Commission's primary statutory purposes and essentially convert Minn. Stat. § 216B.1694, subd. 1(2) into a meaningless formality. To the extent provisions regarding the Commission's duties under Minn. Stat. § 216B.1694, subd. 1(2) are ambiguous, they must be read *in pari materia* with Minn. Stat. § 216B.01, which set forth the purposes for which the Commission was created and its more general duties with regard to the regulation of public utilities.[159] The IEP statute must also be construed in a way that gives effect to all of its provisions.[160] Therefore, the Commission has the authority and duty to look beyond Excelsior's certification that it is "capable of offering a long-term supply contract at a hedged, predictable cost" in order to determine whether or not that is, in fact, the case.

Interpreting Minn. Stat. § 216B.1694, subd. 1(3)

Minn. Stat. § 216B.1694, subd. 1(3) contains another requirement that the Project must meet in order to qualify as an Innovative Energy Project—namely, the Project must have been:

> …designated by the commissioner of the Iron Range Resources and Rehabilitation Board as a project that is located in the taconite tax relief area on a site that has substantial real property with adequate infrastructure to support new or expanded development and that has received prior financial and other support from the board.

The statute does not require that an IEP be located "on a site that has substantial real property with adequate infrastructure to support new or expanded development." Rather it requires that an IEP *have a designation* by the IRR Commissioner—albeit, a designation to that effect. Thus, the question in determining whether a proposed project by Excelsior on the West Range Site meets the definition of an IEP is whether that site has the Commissioner's designation. All of the parties agree that the Commissioner has, in fact, designated both the East Range and the West Range site as having adequate infrastructure. However, in a motion for partial summary disposition filed on September 25, 2006, MCGP argued that it was undisputed that the West Range Site, in fact, lacks "adequate infrastructure" within the meaning of Minn. Stat. § 216B.1694, subd. 1(3), that the IRR Commissioner's designation of that site was erroneous or fraudulent, and, therefore, as a matter of law, Excelsior cannot construct its project on

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[158] *See* Minn. Stat. § 216B.01 and discussion in Part IV-B-5, *infra*.

[159] Minn. Stat. § 216B.01, which sets forth the Legislature's general expectations concerning the Commission's function, and Minn. Stat. §216B,1694, which sets forth the Commission's specific functions with respect to this matter, are clearly so closely related "as to require they be interpreted in light of one another"— in other words, be read in *pari materia*. *See State v. McKown*, *supra*, 475 N.W.2d at 66.

[160] Minn. Stat. § 645.15 (2006).

that site. The question of statutory interpretation is whether the Legislature intended to grant the Commission the authority to review the IRR Commissioner's designation and set it aside if the Commission were to find it to be clearly erroneous or fraudulent.

Reviewing any factual determinations the IRR Commissioner may have made in making the required designation is clearly either a judicial or a quasi-judicial, function. State agencies have no inherent quasi-judicial powers. Accordingly, "[a]gencies are not permitted to act outside the jurisdictional boundaries of their enabling acts."[161] The decision of an agency that lies outside its statutory authority and jurisdiction is subject to reversal by a reviewing court.[162] Here, the Legislature did not give the Commission statutory authority to review the IRR Commissioner's designation. Absent such a grant of quasi-judicial jurisdiction, the Commission has no authority to inquire into the validity of the IRR Commissioner's designation and adjudicate whether the West Range Site, in fact, "has substantial real property with adequate infrastructure to support new or expanded development,". The authority to review the IRR Commissioner's designation of the West Range Site must reside, if at all, in some court of competent jurisdiction.

Interpreting the Provisions of Minn. Stat. § 216B.1694, Subd. 2(a)

Minn. Stat. § 216B.1694, subd. 2(a) provides in part that "An Innovative Energy Project … (4) shall qualify as a "Clean Energy Technology" as defined in section 216B.1693." The phrase "shall qualify" as used in that paragraph is ambiguous. Since "shall" can mean either the imperative form or the future tense of the verb "to be," "shall qualify" could refer either to a requirement—"must qualify"—or to a finding of fact—"is qualified." The latter interpretation is correct because the criteria for defining "Clean Energy Technology" in Minn. Stat. § 216B.1693(c), to which subdivision 2(a)(4) refers, are essentially the same as the first criterion for qualification as an "Innovative Energy Project" in Minn. Stat. § 216B.1694, subd. 1(1). Thus, subdivision 2(a)(4) is merely a recognition that if a project meets all the requirements to be an Innovative Energy Project, it also meets the more limited requirements to constitute a Clean Energy Technology. The subdivision is not an indication that the Legislature has already concluded that the Mesaba Project meets the criteria for a clean energy project.

Interpreting Minn. Stat. § 216B.1694, subd. 2(a)(7)

Minn. Stat. § 216B.1694, subd. 2(a)(7), provides that an Innovative Energy Project "shall be entitled to enter into a contract with a public utility that owns a nuclear generation facility in the state to provide 450 megawatts of baseload capacity and energy under a long-term contract, subject to the approval of the terms and conditions of the contract by the commission."

[161] *Cable Communications Bd. v. Nor-West Cable Communications Partnership*, 356 N.W.2d 658, 668 (Minn. 1984).

[162] Minn. Stat. § 14.69(b) (2006); *see also Hiawatha Aviation of Rochester, Inc. v. Minnesota Dep't of Health*, 375 N.W.2d 496, 501 (Minn. App. 1985)

Amount of Energy under Minn. Stat. § 216B.1694, subd. 2(a)(7)

Xcel Industrial Intervenors (XII) and Xcel have contended that the PPA must be for 450 MW, no more and no less. They argue that the Legislature intended to give the Commission the authority to alter or amend any provision of the PPA, *except* the statutory amount—i.e., 450 MW— of baseload capacity that can be sold. On the other hand, Excelsior argues that the statute authorizes the Commission to alter or amend *any* provision of the PPA, *including* the amount of baseload capacity that can be sold.

The arguments of XII and Xcel are based on the assumption that if the Legislature had intended the Commission to have the authority to alter or amend the amount of baseload capacity in the PPA, it would not have specified an amount certain (i.e., "450 megawatts") or would have established a floor rather than an amount certain for that entitlement (*e.g.*, "at least 450 megawatts"). But that argument requires assumptions about legislative intent that involve speculating about *why* the legislature used the words it chose rather than addressing the plain meaning of the words that the legislature did choose to use. Minn. Stat. § 645.16 provides in part that:

> When the words of a law in their application to an existing situation are clear and free from all ambiguity, the letter of the law shall not be disregarded under the pretext of pursuing the spirit.

There is nothing ambiguous about Minn. Stat. § 216B.1694, subd. 2(a)(7), with respect to the Commission's authority to alter or amend a PPA that an Innovative Energy Project submits for its approval. The statute contains no explicit limitation or qualification on that authority. None of the parties have offered legislative history that explains why the legislature chose 450 megawatts as the baseload capacity amount for a power sale under the PPA. Why the legislature chose that amount is therefore a matter of speculation.[163] However, speculating about why the legislature specified 450 MW sheds no light on the question of statutory interpretation that is really germane here—that is, whether the legislature intended to give the Commission authority to alter or amend that specified amount of baseload capacity. In that regard, the language of the statute speaks for itself. As previously noted, there is no explicit limitation on the Commission's authority to amend that portion of the PPA. Instead, XLI and Xcel Energy argue that the legislature's use of the 450 MW figure for the amount of baseload capacity is, in effect, an *implicit* limitation on the Commission's authority to change that amount during the approval process. But Minn. Stat. § 645.16 and relevant case law

[163] Excelsior suggests that 450 MW was the level of Xcel's projected need at the time the legislation was enacted. Although that would seem to make some sense, there is no admissible evidence that was the Legislature's motivation for specifying that amount. Excelsior also has stated, in its response to DOC IR 102, that at the time the IEP Statute was passed, it appeared that 450 MW of baseload capacity was an optimal size for the Project. However, after further efforts to optimize plant design to reduce costs and improve reliability, ConocoPhillips and Fluor determined that the optimal design would yield 603 MW. DOC 3031 at 1-2. This explanation invites speculation that the Project's entire output of 450 MW would have been what Excelsior Energy's lobbyists requested from the Legislature at the time. But that is speculation, not proof of legislative intent.

permits consideration of implicit legislative intent only when the language of the statute is not explicit and free from ambiguity, and that is simply not the case here.

Public Interest Determination under Minn. Stat. § 216B.1494, subd. 2(a)(7)

If the Project did qualify as an IEP as defined by Minn. Stat. § 216B.1694, subd. 1, the Commission must then make a determination, pursuant to Minn. Stat. § 216B.1694, subd. 2(a)(7), whether to approve, disapprove, amend, or modify the terms and conditions of a proposed power purchase agreement that Excelsior has submitted to Xcel Energy. When the Commission makes that "public interest determination," the Legislature instructed the Commission to consider:

> …the project's economic development benefits to the state; the use of abundant domestic fuel sources; the stability of the price of the output from the project; the project's potential to contribute to a transition to hydrogen as a fuel resource; and the emission reductions achieved compared to other solid fuel baseload technologies

How broad the Legislature intended the scope of that public interest determination to be has emerged as one of the major legal issues in this proceeding. Excelsior takes the position that in making its public interest determination, the Commission may only consider the five factors expressly listed in Minn. Stat. § 216B.1694, subd. 2(a)(7). Excelsior also argues that if the Commission were to conclude that the scope of its public interest determination should is broader than that, Minn. Stat. § 216B.1694, subd. 2(a)(1), which exempt Excelsior from obtaining a certificate of need, precludes the Commission from considering anything it would normally consider in a certificate of need proceeding under Minn. Stat. § 216B.243. On the other hand, all of the intervenors argue for a much broader view of the Commission's public interest determination than the view offered by Excelsior. Xcel expresses that broader view advanced by arguing that the Commission has "full authority to utilize the traditional public interest standard, supplemented by additional factors identified by the Legislature."[164] The question therefore is: To what extent, if at all, did the Legislature intend for the Commission to consider aspects of the public interest that are not enumerated in Minn. Stat. § 216B.1494, subd. 2(a)(7)?

One view that nearly all of the intervenors advocate is that all of the provisions of Minn. Stat. §§ 216B.1693 and 1694 should be read *in pari material*; therefore, the least-cost resource requirement in Minn. Stat. § 216B.1693(1) applies with equal force to the Commission's public interest determination in Minn. Stat. § 216B.1494, subd. 2(a)(7). However, nothing in the IEP statute specifically incorporates the least-cost resource criterion in the CET statute or otherwise specifically requires the Commission to

[164] Xcel Energy's Initial Brief at 6; *see also* Minnesota Chamber of Commerce's Initial Brief (hereafter Minnesota Chamber's Initial Brief) at. p. 11 and Initial Brief of Manitoba Hydro at 4.

determine whether IGCC is a least-cost resource when considering whether or not to approve the proposed PPA between Excelsior and Xcel Energy.[165]

Minn. Stat. § 216B.1694, subd. 2(a)(7), should not be read in pari materia with Minn. Stat. § 216B.2422

Most intervenors argue that the Commission should consider whether or not Xcel will need the power that Excelsior proposes to supply under the PPA. Many simply argue that the Commission has a broad mandate to consider anything that bears on the public interest, and that Xcel's future need for power is one of those public interest factors.[166] What argues strongly against that view is the Legislature's exemption of Excelsior from having to obtain a certificate of need under Minn. Stat. § 216B.243.[167] Some, however, attempt to take a narrow view of what that exemption means by arguing that Minn. Stat. § 216B.1694, subd. 2(a)(7), must be read *in pari materia* with the resource planning statute, Minn. Stat. § 216B.2422.[168] They argue that the two statutes, when read together, establish that it is appropriate for the Commission to take into account Xcel's need for power as evidenced in its most recent resource plan in determining whether to approve the PPA. More specifically, they contend that the Legislature intended that the Commission's consideration the 2004 integrated resource plan that Xcel prepared pursuant to Minn. Stat. § 216B.2422 to be the exclusive process for prospective power suppliers, including Excelsior, to submit proposals to meet Xcel's future needs. They claim that since Excelsior did not propose to supply Xcel with power in the course of that process and since the Commission has already approved Xcel's 2004 resource plan, the Commission must now disapprove the PPA as being contrary to the public interest because compelling Xcel to purchase 450 MW of power from Excelsior would result in not giving effect to that earlier resource planning process and the resultant resource plan.

Xcel's 2004 integrated resource plan indicates that Xcel does have a future need for baseload power, but the extent of Xcel's future needs is not the issue here. The issue is whether the Legislature intended some or all of those needs to be met by Excelsior, if it meets the requirements of Minn. Stat. § 216B.1694 rather than by other power suppliers who may have submitted proposals in the course of Xcel's 2004 resource planning process. In other words, it appears that a conflict may exist between the results of Xcel's resource planning pursuant to Minn. Stat. § 216B.2422 and the Legislature's directive in Minn. Stat. § 216B.1694 for Xcel to purchase power from an IEP. Where the intervenors' argument misses the mark is how they have reconciled that conflict. In effect, they have read an additional requirement into Minn. Stat. §

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[165] Xcel and other parties may argue that the statutory requirement in Minn. Stat. § 216B.1694, subd. 2(a)(7), that the Commission make a "public interest determination" implicitly requires the Commission to consider the project's costs. That may well be the case, but consideration of project costs in general falls short of a specific determination that IGCC is a "least-cost resource."

[166] See Xcel Energy's Initial Brief at 22-23 and Reply Brief at 11-12; Initial Brief of Izaak Walton League of America, Fresh Energy and Minnesota Center for Environmental Advocacy at 3-7.

[167] See Minn. Stat. § 216B.1694, subd. 2(1).

[168] *See* Minnesota Power's Initial Brief at 22-26.

216B.1694 for an IEP to meet—namely, that to be entitled to a PPA, the sponsor of the IEP must first have submitted a proposal to Xcel to provide it with power during Xcel's most recent resource planning process. Again, one cannot read into a statute what the Legislature has left out."[169] Additionally, the more specific IEP statutory provisions relating to how Xcel must obtain the power it will need must prevail over the results of the resource planning process set forth in the more general provisions of Minn. Stat. § 216B.2422. It is the rule that specific provisions in a statute control general provisions; that provisions of a complete and specific act will prevail over general language of another, prior provision, and if there is conflict between different statutes as to the same matter, the later statute prevails.[170]

Minn. Stat. § 216B.1494, subd. 2(a)(7), should be read in pari materia with Minn. Stat. §§ 216B.01 and 216B.03

The Commission has no inherent powers to consider aspects of the public interest. Rather, the Commission is a creation of statute and may only exercise the powers that the Legislature has expressly granted to it. If the Commission has the authority to consider public interest factors other than those enumerated in subd. 2(a)(7) of the IEP statute, then that authority must be firmly grounded in some other provision of the IEP statute or other section of Chapter 216B. Neither Minn. Stat. § 216b.1693(a) nor Minn. Stat. § 216B.2422 operates to broaden the scope of the Commission's public interest determination under Minn. Stat. § 216B.1494, subd. 2(a)(7). However, the language of the IEP statute— "in making *its* public interest determination"—suggests that the Legislature was referring to some pre-existing statutory basis for the Commission's consideration of some public interest factors that the succeeding five factors were to supplement. To hold otherwise would render the phrase, "in making its public interest determination," in the statute superfluous. If the Legislature had intended that the inquiry be limited to the five factors, it could have left the phrase out entirely or changed it to read, "The commission may approve, disapprove, amend, or modify the contract in making its public interest determination, taking into consideration <u>only</u> the project's . . ." It did not do so. The statute must be read so as to give effect to all of its provisions.[171]

There are additional reasons to apply the broader public interest standard. Minnesota Statutes, Chapter 216B, is entitled and expressly pertains to "Public Utilities." Thus, two threshold questions are whether Excelsior is a "public utility" within the meaning of Chapter 216B and, if so, whether that operates to broaden the Commission's public interest determination beyond the five factors listed in Minn. Stat. § 216B.1494, subd. 2(a)(7). "Public utility" is defined in Minn. Stat. § 216B.02, subd. 4, which provides in part:

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[169] *Koes v. Advanced Design, Inc.*, 636 N.W.2d 352, 359 (Minn. 2001).
[170] *Fink v. Cold Spring Granite Co.*, 115 N.W.2d 22, 26 (Minn. 1962), citing *Beck v. Groe*, 70 N.W. (2d) 886, 895 (Minn. 1955).
[171] Minn. Stat. § 645.15 (2006); *See Owens v. Federated Mut. Implement & Hardware Ins*., 328 N.W.2d 162, 164 (Minn. 1983).

> "Public utility" means persons, corporations, or other legal entities, their lessees, trustees, and receivers, now or hereafter operating, maintaining, or controlling in this state equipment or facilities for *furnishing at retail* natural, manufactured, or mixed gas or electric service to or for the public or engaged in the production *and retail sale* thereof … [Emphasis supplied.]

Reading Minn. Stat. § 216B.02, subd. 4, it first appears that the Legislature was only concerned with regulation by the Commission of *retail sales* of electrical power by public utilities. However, Minn. Stat. § 216B.02, subd. 4, goes on to indicate that some wholesale sales of electrical power might also be subject to regulation:

> *Except as otherwise provided*, the provisions of this chapter shall not be applicable to any sale of natural, manufactured, or mixed gas or electricity by a public utility to another public utility for resale. [Emphasis supplied.]

Although Excelsior might not precisely meet the definition of a public utility, the Legislature clearly understood that Xcel and Minnesota Power, the potential wholesale purchaser of power from Excelsior and the power provider that will be financially responsible for transmission lines connecting the Project to the grid, are public utilities.[172] Put another way, even though Excelsior might not meet the definition a "public utility" within the meaning of Chapter 216B and be subject to regulation by the Commission as such, Xcel and Minnesota Power are clearly subject to regulation by the Commission as a public utilities, as are Xcel's potential obligations to purchase power from Excelsior. The question, then, is whether the Commission's jurisdiction over Xcel and Minnesota Power, and the power purchases that the CET and IEP statutes potentially require Xcel to make from Excelsior, operate to broaden the Commission's public interest determination under Minn. Stat. § 216B.1694, subd. 2(a)(7), beyond the five factors that the Legislature specifically lists in that statute.

The Commission's general responsibilities to regulate Minnesota Power and Xcel do broaden the Commission's public interest determinations under the CET and IEP statutes. Minn. Stat. § 216B.01, which contains the Legislature's findings with regard to the Commission's regulation of public utilities, provides, in part:

> It is hereby declared to be in the public interest that public utilities be regulated as hereinafter provided in order to provide the retail consumers of natural gas and electric service in this state with adequate and reliable services at reasonable rates, consistent with the financial and economic requirements of public utilities and their need to construct facilities to provide such services or to otherwise obtain energy supplies, to avoid unnecessary duplication of facilities which increase the cost of service to

[172] Minn. Stat.§ 216B.1694, subd. 2(a)(7), gives the Commission jurisdiction over a Innovative Energy Project's "contract with a public utility that owns a nuclear generation facility in the state …:

> the consumer and to minimize disputes between public utilities which may result in inconvenience or diminish efficiency in service to the consumers

The Department argues that the Commission must also consider its responsibilities under Minn. Stat. § 216B.03, Reasonable Rates, which states, in part:

> Every rate made, demanded, or received by any public utility, or by any two or more public utilities jointly, shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers. To the maximum reasonable extent, the commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05. Any doubt as to reasonableness should be resolved in favor of the consumer.

The Department goes on to argue that Minn. Stat. §§ 216B.1693 and1694 did not revoke this provision of law, so it is clear that the reasonableness of the rate (cost) must be included as a main factor in determination of the public interest in this proceeding.[173]

By exempting the Project from the certificate of need statute, the Legislature has indicated that neither need to construct facilities nor unnecessary duplication of facilities are matters that the Commission should consider in this proceeding. But the Legislature has said nothing to prevent the Commission from considering how the Project might impact providing "retail consumers of … electric service in this state with adequate and reliable services at reasonable rates." As Dr. Amit puts it, despite exemption from the CON process, the issue of Xcel Energy's need is closely tied to the issue of the Project being a least cost resource for Xcel Energy. Because all the capacity and electricity will not be needed by Xcel for at least the first four years of the PPA, Xcel's ratepayers would have to pay, under the PPA, much higher prices than they would have to pay otherwise over the period 2011 through 2014.[174] In short, in addition to the five factors set forth in Minn. Stat. § 216B.1494, subd. 2(a)(7), the Commission still has a statutory duty to consider the impact the Project will have on ratepayers and the financial and economic requirements of Xcel Energy.

Excelsior Energy also suggests that the Legislature already largely balanced the interests of rate payers and other stakeholders when it enacted the CET and IEP statutes, and that the Legislature concluded that Excelsior should be allowed to proceed with the Project unless it simply could not meet the statutory conditions set forth in the two statutes. The view of the intervenors is essentially that the Legislature intended the Commission to balance all aspects of the public *de novo*. The intervenors contend that upon completion of a *de novo* balancing of interests, the Commission should postpone development of an IGCC baseload energy source in Minnesota indefinitely until the reliability of the technology is better established, until its potential to use carbon capture

[173] Department's Reply Brief at 6.
[174] EE 3018 at 36.

and sequestration can be realized, and until Xcel Energy has a clear need for the baseload capacity that the Project will create.

Reading Minn. Stat. §§ 216B.1693 and 216B.1694 together with Minn. Stat. §§ 216B.01 and 216B.03, there is nothing in those statutes that manifests a legislative intent for the Commission's review of the Project to be as perfunctory as Excelsior argues, nor did the Legislature intend to empower the Commission to postpone the Project indefinitely until all of the concerns the intervenors raise are completely satisfied. Both of those views of legislative intent are incorrect. Rather, it appears the Legislature intended to balance some of the relevant interests during the process of enactment, but leave some degree of balancing of interests for the Commission to complete. In short, the legislative intent that emerges from the relevant legislation is that the Commission should allow Excelsior to proceed with the Project and create in the near future the additional baseload capacity that the Project represents unless Excelsior cannot meet the statutory conditions that the Legislature has established and unless there is likely to be such an adverse impact on rate payers and Xcel Energy that proceeding with the Project by approving the PPA will result in more long-term harm than good.

Interpreting the Five Factors in Minn. Stat. § 216B.1494, subd. 2(a)(7)

There appear to be two additional significant interpretation issues relating to the five public interest factors listed in Minn. Stat. § 216B.1494, subd. 2(a)(7). The first of those factors is "the project's economic development benefits to the state." The intervenors argue that the Legislature intended the Commission to consider the Project's "net" economic development benefits to the state—that is, both the positive and negative impacts that the Project will have on economic development within the state. On the other had, Excelsior contends that the Legislature intended the Commission to consider only the Project's economic development "advantages" but not any "disadvantages" it may produce. Excelsior argues that if the Legislature intended to delegate to the Commission the question of an IEP's economic development "impacts" or "net impacts," or "net benefits," or even "costs and benefits" in making its public interest determination, it would have so stated. To support that construction, Excelsior relies on the proposition that an administrative agency does not have the "authority to determine what the law should be or to supply a substantive provision of law which [it] thinks the legislature should have enacted in the first place."[175] But contrary to Excelsior's contention, this is not a situation where intervenors are attempting to supply a word that is absent from the statute. Rather it is a situation where the Legislature has not clearly and unambiguously defined what it intends the scope of the Commission's assessment of the Project's effect on the state's economic development to be. The sense of the term "benefit" that is most apposite to its context here is "[s]omething that promotes or enhances well-being."[176] Accordingly, the Commission's inquiry into economic development is an inquiry to the extent to which the Project will contribute to the state's economic development and economic well-being. Assessing that

[175] *Citing Wallace v. Comm'r of Taxation,* 289 Minn. 200, 184 N.W.2d 588, 594 (1971).
[176] AMERICAN HERITAGE DICTIONARY (2nd College Ed. 1985) at 171.

contribution necessarily involves analysis of how the Project will both positively and negatively affect economical development. Another settled canon of statutory construction is that "the legislature does not intend a result that is absurd, impossible of execution, or unreasonable."[177] It is unreasonable to presume that if the Project would, in the aggregate, do more harm than good for the state's economic development efforts, the Commission may only consider the good and not the harm.

The intervenors go on to argue that Minn. R. 1400.7300, subp. 5, then requires Excelsior to produce evidence of the Project's economic development disadvantages, as well of its economic development advantages. They argue that since Excelsior did not produce evidence of potential disadvantages, it did not meet its burden of proof with respect to that issue. The intervenors are misinterpreting the "burden" that Minn. R. 1400.7300, subp. 5, establishes. The "burden" that the rule defines is the burden of *persuasion*—that is, the burden of persuading the fact finder of the truth of the facts asserted and the reasonableness of proposals advanced.[178] It is not the burden of going forward with evidence, which the rules do not specifically address. The burden of going forward with evidence may "shift back and forth among the parties during the presentation of evidence in a case."[179] A contested case, such as this, is an adversary proceeding in which the burden of going forward with evidence can shift. In short, unless it would amount to misleading the ALJs and the Commission, Excelsior's obligation here is only to provide evidence supporting its position. Excelsior has been explicit about the fact that it has only produced evidence of positive economic development benefit, and there is no evidence of any intent to mislead anyone about that.

The fifth public interest factor that the Legislature specifically listed in Minn. Stat. § 216B.1494, subd. 2(a)(7), is "the emission reductions achieved compared to other solid fuel baseload technologies." This is similar t o, but not identical to requiring the Project to be an IGCC and have significantly reduced sulfur dioxide, nitrogen oxide, particulate, and mercury emissions when compared to traditional technologies under Minn. Stat. § 216B.1694, subd. 1(1). The comparison to be made is not restricted to the four criteria emissions and there is no expressed requirement that emissions be "significantly reduced." Further, the comparison must be between the Project and "other solid fuel baseload technologies," rather than to "traditional technologies." The net result is to broaden the comparison to include CO_2 emissions, which all parties agree should be considered to some extent. It also means that CFB plants could be considered, but no substantial evidence has been presented in this matter regarding the enhanced, second generation CFB plants.

Current concern over the issue of climate change and the extent to which carbon dioxide may be contributing to global warming has generated considerable interest in carbon capture and sequestration. In a hearing conducted by the Commission on July

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[177] Minn. Stat. § 645.17(1).
[178] *In re Minnesota Public Utilities Commission*, *supra*, 365 N.W.2d at 343.
[179] GEORGE W. BECK, ET AL., MINNESOTA ADMINISTRATIVE PROCEDURE § 10.3.1 (2nd ed. 1998); *see also Peterson v. Minneapolis Street Ry.*, 31 N.W.2d 905, 909 (Minn. 1948).

27, 2006, several members of the Commission indicated interest in the Project's potential to capture and sequester carbon and requested Excelsior to provide the Commission with information concerning that possibility.[180] First, it should be noted that that Commission meeting occurred three months *after* the Commission had issued its Notice of Hearing in this matter and referred it to the Office of Administrative Hearings. There is no mention of carbon capture and sequestration in the Notice of Hearing. In other words, the fact that Commission members may be interested in the Project's potential to capture and sequester carbon does not necessarily mean that the Commission has concluded that that potential and any associated costs are factors that the Commission had to consider in determining whether to approve the proposed PPA.[181]

Nevertheless, nearly all of the parties appear to assume that the issue of carbon capture and sequestration is relevant to the issues of whether the PPA should be approved, whether the Project is, or is likely to be, a least-cost resource, or both. Excelsior suggests that its Project's potential to incorporate carbon sequestration technology as a *potential* benefit, which the Commission should consider in determining whether to approve the PPA.[182] Other parties either argue that it is not a benefit the Commission should consider or suggest that if it is, then the cost of carbon capture and sequestration should be considered in determining the Project's cost.[183]

First, the Legislature specifically addressed the Project's potential for carbon capture and sequestration in Minn. Stat. § 216B.1694, subd. 2(a)(6):

> [The Innovative Energy Project] shall make a good faith effort to secure funding from the United States Department of Energy and the United States Department of Agriculture to conduct a demonstration project at the facility for either geologic or terrestrial carbon sequestration projects to achieve reductions in facility emissions or carbon dioxide;

Thus, the Legislature was aware of the carbon capture issue and specifically authorized and required Excelsior Energy to seek available government funding. It likely did it so because such funding would help reduce the cost of the capacity and electricity provided under the PPA.

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[180] EE 1177 at 12-14.

[181] In fact, it appears that the Commission did not bring up the issue of carbon management *sua sponte* at its July 27, 2006, meeting as something it should consider in determining whether to approve the PPA. Rather, it appears that the Commission's request for information responded to statements by Excelsior that carbon management would be a *potential benefit* of the Project. *Id*. at 14.

[182] Excelsior Energy Inc.'s Findings of Fact, Conclusions and Recommendation at ¶¶ 335-391. The ALJs note that Excelsior apparent argument that the Commission should consider the Project's potential for carbon capture and sequestration as a benefit to be considered in determining whether to approve the PPA appears somewhat inconsistent with its more general argument that the Commission is limited to considering the five factors expressly set forth in the subdivision 2(a)(7).

[183] *For examples, see* Xcel Energy's Initial Brief at 14; Minnesota Power's Initial Brief at 18; Initial Brief of the Minnesota Department of Commerce (hereafter "Department's Initial Brief) at 40-42.

The evidence establishes that "experts agree that extensive research and large-scale demonstration projects are needed on sequestration before a commercial IGCC or other coal powered plant would be in a position to sequester its CO_2."[184] In other words, the potential benefits and costs of carbon sequestration are still largely speculative. However, there is little doubt today that there will be future legislation on both the state and federal levels that will impose requirements on fossil-fuel burning power plants either to reduce greenhouse gas emissions or to pay for other methods of reducing those gases. We can also speculate that such legislation could possibly result in both financial benefits and costs for the Project. For example, it is possible that the Project might someday be able to achieve significant reductions of greenhouse gases through carbon capture and sequestration, but offset that cost to some degree by selling the sequestered CO_2 or carbon credits. At this point, prudent practice requires that utility planners consider the possible costs of carbon regulation.

Interpreting the CET Statute, Minn. Stat. § 216B.1693

In Minn. Stat. § 216B.1693, the Legislature required the Commission to make several separate, but related determinations. In logical sequence, the Commission must first determine whether Excelsior's Mesaba Project employs "Clean Energy Technology" within the meaning of Minn. Stat. § 216B.1693(c). The statutory definition of "Clean Energy Technology," in turn, requires application of a three part test: (1) whether the Mesaba Project is based on a "technology utilizing coal as a primary fuel"; (2) whether it uses that coal "in a highly efficient combined-cycle configuration"; and (3) whether use of that technology results in "significantly reduced sulfur dioxide, nitrogen oxide, particulate, and mercury emissions from those of traditional technologies." This three-part test in Minn. Stat. § 216B.1693(c) is identical to the three-part test in Minn. Stat. § 216B.1694, subd. 1(1), which comprises part of the definition of "Innovative Energy Project." Both of the provisions have the same meaning. In other words, if Excelsior's project qualifies as an Innovative Energy Project under Minn. Stat. § 216B.1694, subd. 1, it also necessarily qualifies as a Clean Energy Technology under Minn. Stat. § 216B.1693(c).

The Term "Least-Cost Resource" Must Be Interpreted With Reference to the Resource Planning Statute, Minn. Stat. § 216B.2422

Being a "least-cost resource" is an express requirement for Excelsior to be eligible to supply two percent of Xcel's retail load in addition to whatever sale the Commission may approve under the PPA. The Legislature did not define "least-cost resource" in Minn. Stat. § 216B.1693 or elsewhere in Minn. Stat. Ch. 216B. However, Minn. Stat. § 216B.2422, subd. 2, does refer to "least cost plan":

> As a part of its resource plan filing, a utility shall include *the least cost plan* for meeting 50 and 75 percent of all new and refurbished capacity needs

[184] EE 1028.5 at 6.

through a combination of conservation and renewable energy resources. [Emphasis supplied.]

In the resource planning process, a public utility, such as Xcel, evaluates a variety of potential resource options for supplying its projected need for electric energy. The various options are analyzed to determine their cost effectiveness, and alternatives are modeled and compared with one another under a variety of scenarios to find the least cost resource mix. In other words, the term "least cost resource" appears to be a technical term used within the energy industry to describe a potential electric energy supply resource that is reasonable for a public utility to include in its integrated resource plan. Although there appear to be no objective standards to determine reasonableness in that context, the cost impact on Xcel's rate payers of including power supplied by Excelsior in an amount equal to two percent of Xcel's retail load would appear to be the primary consideration. In other words, since it is the least-cost mix in Xcel's integrated resource plan that will be affected by an obligation to purchase energy from Excelsior in an amount equal to two percent of Xcel's retail load, "a least-cost resource" means a least-cost resource for Xcel.

As previously noted, Minn. Stat. § 216B.01, which must be read in pari material with Minn. Stat. § 216B.1693, declares it "to be in the public interest that public utilities be regulated as hereinafter provided in order to provide the retail consumers of natural gas and electric service in this state with adequate and reliable services at reasonable rates." So the question presented is whether requiring Xcel to purchase 153 MW of power supplied by Excelsior at the projected rate will result in adequate and reliable services for Xcel's retail customers at reasonable rates.

The Public Interest Determination under the CET Statute is Similar to the Public Interest Determination under the IEP Statute.

Minn. Stat. § 216B.1694, subd. 2(a)(7), requires the Commission to make a public interest determination in deciding whether to approve, disapprove, amend, or modify the PPA. The Legislature did not intend the public interest determined required by that statute to be all-encompassing. Rather, that public interest determination has relatively well-defined boundaries. First, the IEP statute expressly lists five factors that the Commission must consider in making that public interest determination. Moreover, by operation of Minn. Stat. §§ 216B.01 and 216B.03, the Commission must also consider the impact that the PPA will have on Xcel and its rate payers, including an inquiry into the reasonableness of rates paid by Xcel Energy under the PPA. The intervenors in this proceeding either argue or assume that the Commission's public interest determinations in the IEP and CET statutes are coterminous. That is not entirely correct. It is possible to imagine that a rate charged under the PPA might be "reasonable," but not be "a least cost resource." But the difference between the two is not great. A rate cannot be found to be reasonable if it is significantly greater than rates for identical service from other providers, absent some other justification.

SMM/BHJ

Implementation of Clean Air Act Requirements for Advanced Coal Technologies

Steve Jenkins

CH2MHILL

Tampa, FL

Advanced Coal Technology Work Group
March 6, 2007

Topics

- Bob Wayland has discussed overall CAA:
  - Rules and how they apply to utility sector
  - Timeline
  - Regulatory process
  - Projected emissions and retrofits to comply with CAIR, CAMR, CAVR
  - BACT and LAER
- Now let's see how ACTs that being planned are going to comply with these rules:
  - How emission control systems for PC and IGCC are different
  - Focus on New Source Performance Standards
  - How emission limits compare

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Applicable Air Regulations

- National Ambient Air Quality Standards (NAAQS)
- New Source Review (NSR) requirements, including Prevention of Significant Deterioration (PSD) and Non-Attainment NSR; and BACT/LAER
- New Source Performance Standards (NSPS)
- National Emission Standards for Hazardous Air Pollutants (NESHAPs) including proposed Utility MACT and Combustion Turbine MACT rules
- Federal Acid Rain Program (Title IV)
- Operating permit (Title V)
- Clean Air Interstate Rule (CAIR)
- Clean Air Mercury Rule (CAMR)

Technology Comparison

	PC	IGCC
Feedstock	-	Coal
Fuel	Coal	Syngas
Combustion	Coal in boiler	Syngas in gas turbine
Emission Control	Post-combustion clean-up of large volume of exhaust gas	Pre-combustion clean-up of small volume of syngas

Comparison of Air Emission Controls: PC and IGCC

	SO_2	NOx	PM	Mercury
PC	Limestone-based FGD system	Low-NOx burners and SCR	ESP or baghouse	Inject activated carbon into flue gas
IGCC	Amine system removes H_2S from syngas	Syngas saturation and N_2 diluent	Wet scrubber, high temperature cyclone, ceramic filter	Pre-sulfided activated carbon bed in syngas stream

IGCC - a Different Environment Than PC

- Gasification occurs in a reducing atmosphere
  - sulfur compounds are liberated as H_2S and COS
  - removed by refinery industry technologies to levels ≥99%
- Low levels of H_2S in the syngas are burned in the gas turbine and become SO_2 in exhaust
- NOx is controlled by injecting N_2 at ~1:1 ratio with syngas, as well as saturating the syngas stream with water or steam (cools the flame)

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New NSPS

Emission	NSPS	NSPS on Input Basis for IGCC (estimated)	NSPS on Input Basis for PC (estimated)
NOx	1.0 lb/MWh*	0.132 lb/MMBtu	0.11 lb/MMBtu
SO_2	1.4 lb/MWh* and minimum 95% removal	0.185 lb/MMBtu	0.155 lb/MMBtu
PM	Lesser of 0.14 lb/MWh* or 0.015 lb/MMBtu	0.015 lb/MMBtu	0.015 lb/MMBtu
Mercury	20 x 10^{-6} lb/MWh* (bituminous)	2.6 lb/TBtu	2.2 lb/TBtu

***output-based standards are on a gross generation basis, so gross heat rate is used to calculate estimated input-based limit**

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New Source Performance Standards

- NSPS for Electric Utility Steam Generating Units (Subpart Da), February, 2006:
  - Applies to IGCC combustion turbines that burn ≥ 75% “synthetic coal gas”
  - When burning <75% syngas (12-month rolling average), Subpart KKKK applies
    - This could be a problem during initial start-up
    - Meeting the NSPS for NOx may not be possible when burning natural gas in diffusion burners designed for syngas
  - Industry requested modification to regulations

New Source Performance Standards

- EPA proposed changes in February 2007
- IGCC is only covered by subpart Da, if:
  - "The combined cycle gas turbine is designed and intended to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas on a 12-month rolling average basis; and
  - The combined cycle gas turbine commenced construction, modification, or reconstruction after February 28, 2005."

New Source Performance Standards

- *Coal-fired electric utility steam generating unit* means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other fuels in any amount.

New Source Performance Standards

- *Integrated gasification combined cycle electric utility steam generating unit* or *IGCC* means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No coal is directly burned in the unit during operation.

Air Permitting Requirements

- IGCC and PC plants are similar
  - Fugitive dust controls
    - Coal delivery, unloading and handling
  - Cooling towers
    - But IGCC cooling towers would have lower duty since only 40% of plant output is from steam turbine generator
  - Air dispersion modeling
  - BACT analysis for emission controls

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Air Permitting: IGCC

- Unique emission points depend on technology provider
  - Flare
  - Start-up burner
  - Gasifier pre-heat burner
  - Sulfur Recovery Unit tail gas incinerator
  - Sulfuric Acid Plant stack
  - Tank vents
  - Air Separation Unit cooling tower

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Air Permitting: IGCC

- For air permit application:
  - Inventory of emission points has to be developed early in the engineering process
  - Emission limits in lb/hr are easier for measurement and compliance than ppm or lb/MMBtu
  - Startup, shutdown and emergency emissions must be calculated – and can be substantial
  - Emissions from flare are critical
    - Raw syngas
    - Clean syngas
    - Duration
    - Number of flare events/year

What About SCR for IGCC?

- Technical issues
  - The fuel is syngas, not natural gas as in NGCC
  - Ammonium sulfate/bisulfate deposits in the HRSG, causing corrosion and plugging, requiring more downtime for washdowns
  - Possible poisoning of SCR catalyst from syngas
  - No coal-based IGCC system in the world uses SCR
- Economic Issues
  - No commercial guarantees yet with syngas
  - SCR would require deeper sulfur removal to reduce sulfate formation to low levels
    - Selexol
    - Higher capital costs

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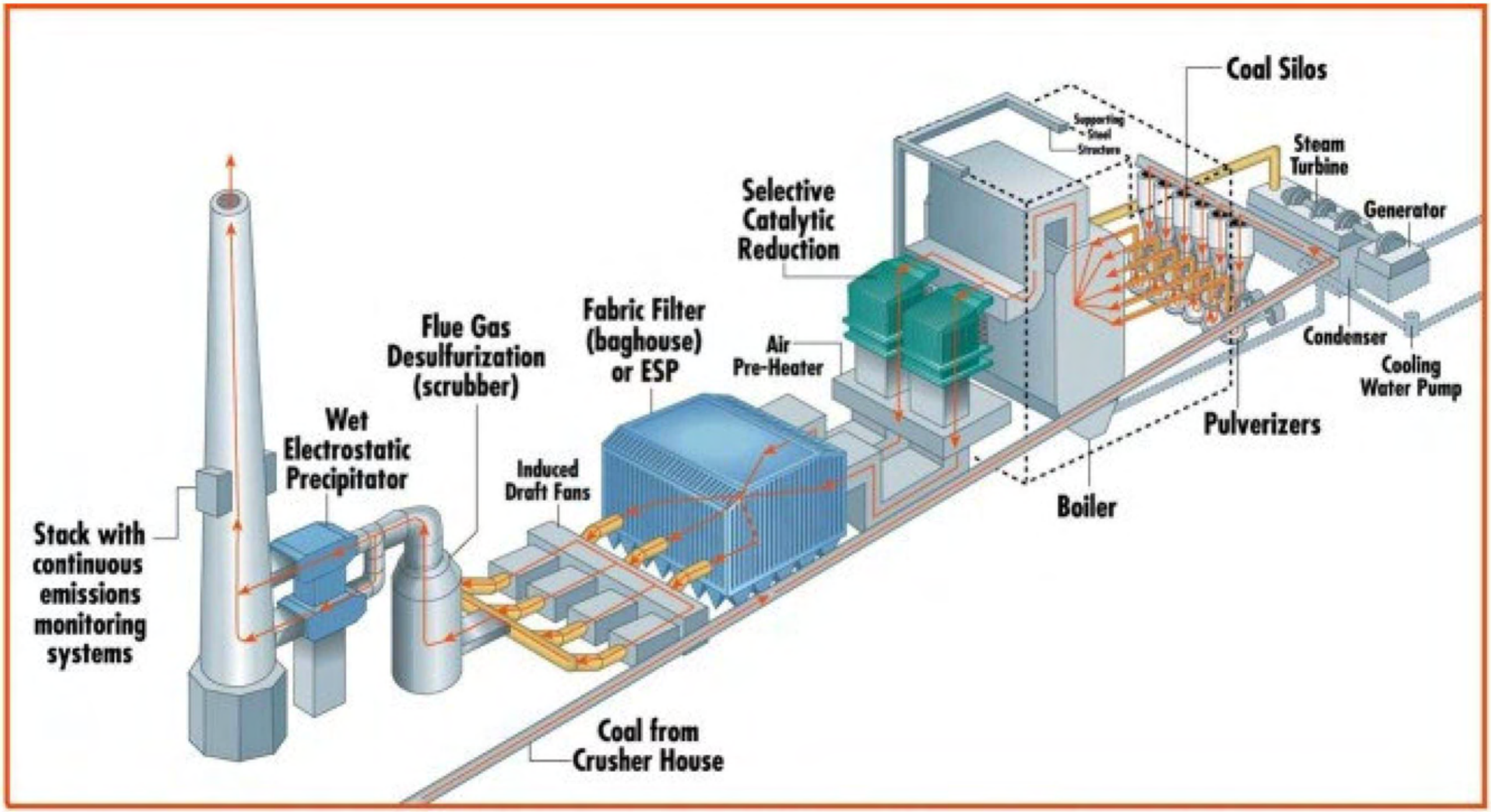
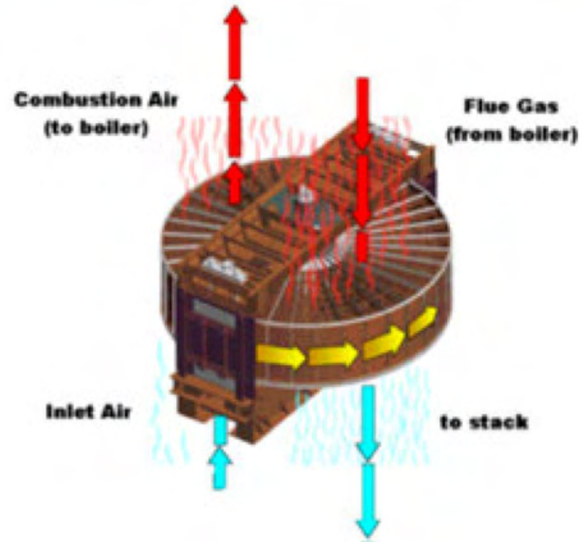
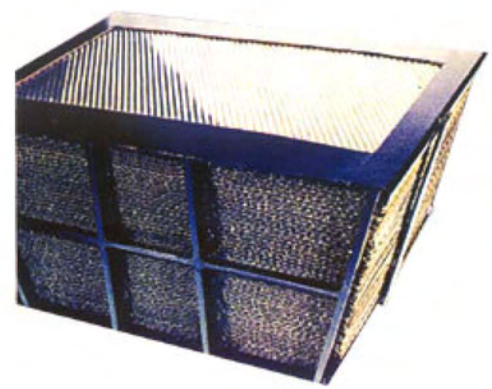
SCR in a PC Plant



SCR: PC vs IGCC

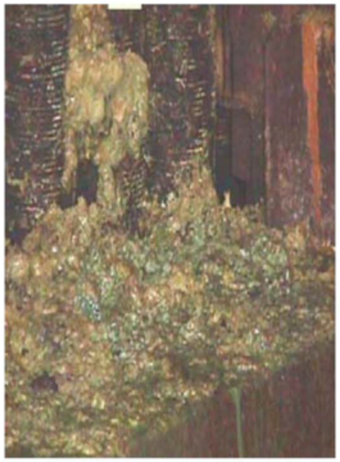
- SCR in a PC plant
  - Air pre-heater baskets:
    - have large openings due to the fly ash in the exhaust gas stream
    - are designed for removal, replacement and cleaning
  - Particulates are removed downstream in the ESP, FGD system, or baghouse





SCR: PC vs IGCC

- SCR in an IGCC plant
  - heat transfer occurs in the HRSG
    - on fixed finned tubing with small clearances
    - designed for exhaust gas from natural gas combustion – no sulfates/bisulfates
    - sulfate/bisulfate deposition would be a problem on finned tubing
    - finned tubing is not designed for removal, replacement or easy cleaning

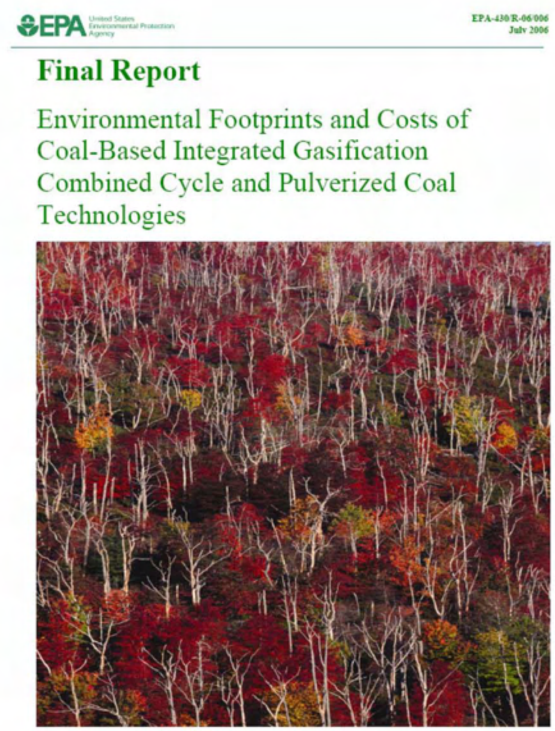


Why SCR?

- But more IGCC plants are being proposed with SCR than without SCR
- Reasons:
  - As BACT
  - As Innovative Control Technology to reduce emissions beyond diluent injection
  - As a trial/experiment, with emission limits proposed only for natural gas use
  - To evaluate SCR as part of DOE demonstration program with a syngas-fired combined cycle unit
  - To minimize NOx emissions in order to reduce NOx emission allowance costs

NOx BACT

- EPA has addressed this issue
- Report notes technical problems with using SCR w/IGCC
- Looked at SCR w/Selexol for deep sulfur removal
- EPA concluded that:
  - even w/Selexol, problems are not solved
  - additional cost and reduced output are negative impacts to IGCC
  - BACT will continue to be a case-by-case issue


EPA United States Environmental Protection Agency

EPA-430/R-06/006
July 2006

Final Report

Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies

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Mercury Removal: PC

- Inject activated carbon in flue gas stream
- Mercury adsorbed onto carbon particle
- Particles removed in ESP or baghouse

Mercury Removal: IGCC

- Pre-sulfided carbon beds in syngas stream
- Forms a mercury-sulfur complex
- Spent carbon disposed of in drums once/year
- Most IGCC plants plan to use this technology

Source: Eastman Chemical

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NOx and SO_2 Emissions

- NOx emission rates not very different for proposed PC and IGCC units

- IGCC units being proposed with much lower SO_2 emission rates
  - due to ability to remove higher percentages of H_2S vs SO_2

- Mercury emission rates about the same for PC and IGCC

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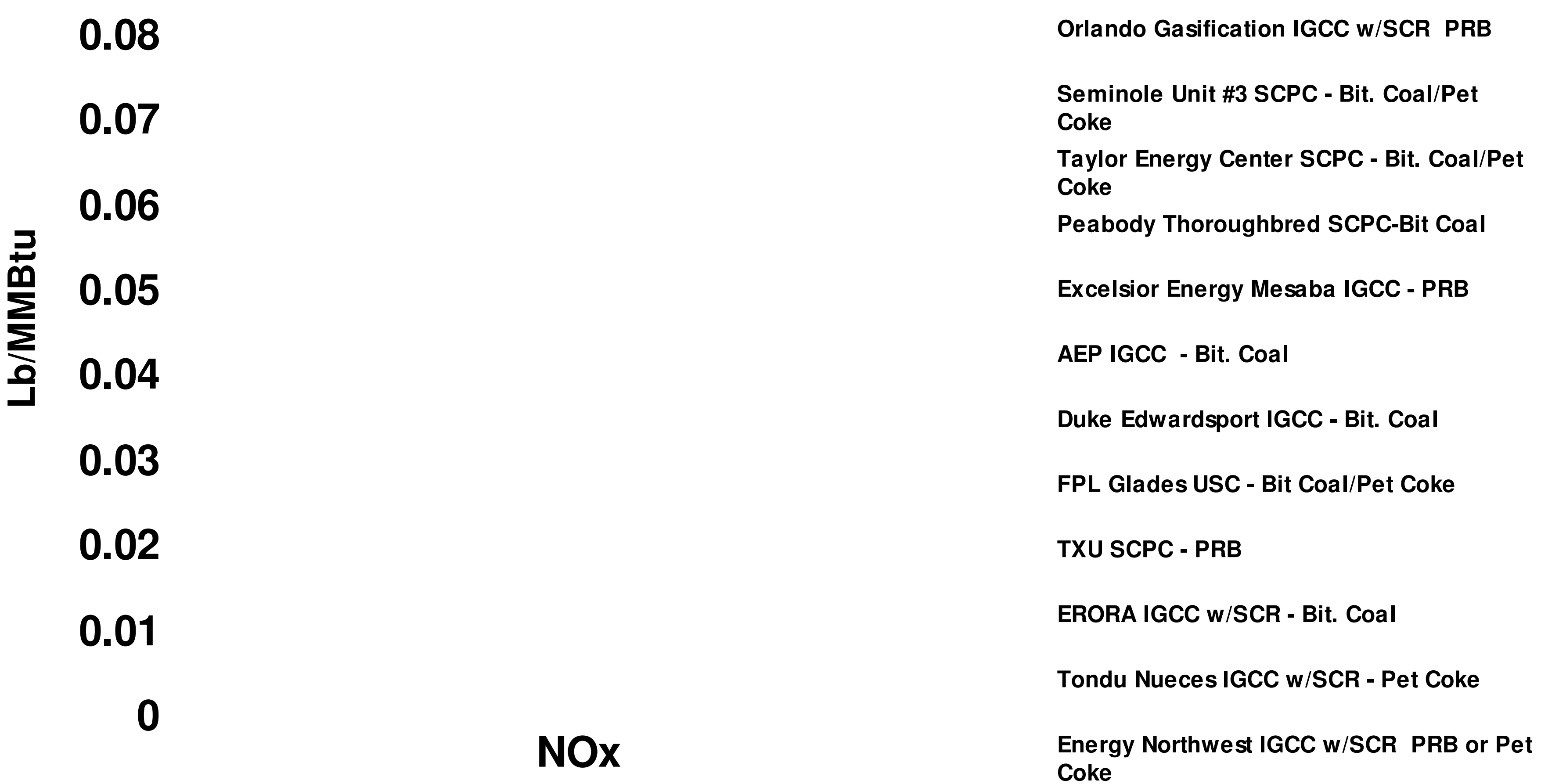
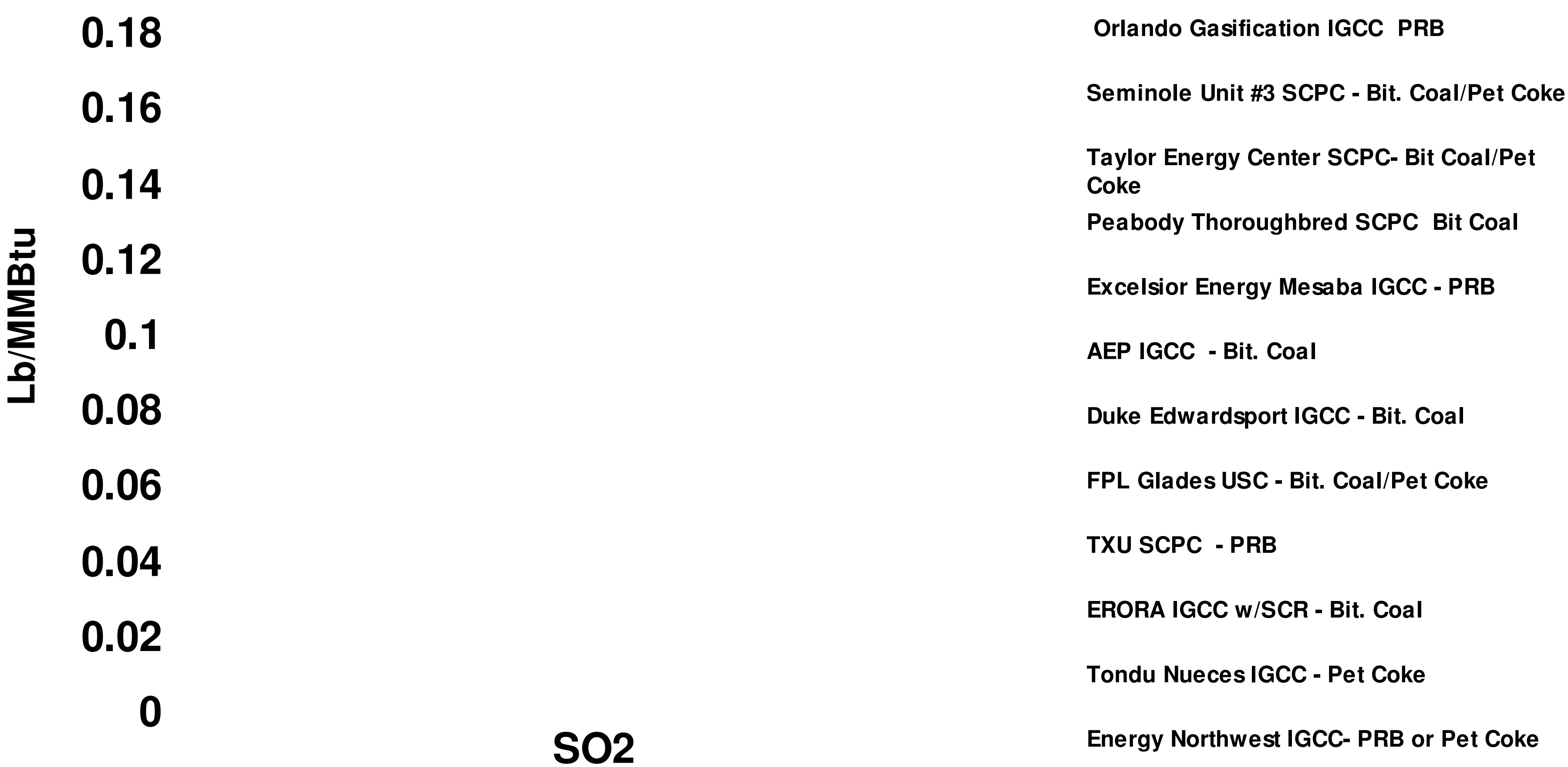
Air Emission Comparisons - NOx



Air Emission Comparisons – SO_2



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January 14, 2004

<u>CERTIFIED MAIL</u>
<u>RETURN RECEIPT REQUESTED</u> IN REPLY REFER TO: 4530-1

Mr. Scott A. Patulski
Vice President, Fossil Operations
231 W. Michigan
Milwaukee, WI 53201

Dear Mr. Patulski:

Your application for an air pollution control construction permit has been processed in accordance with sec. 285.61, Wis. Stats.

The enclosed construction permit is issued to provide authorization for your source to construct and initially operate an Electric Generating Facility referred as Elm Road Generating Station – North Site With Accommodations at 4801 E. Elm Road, Oak Creek, Wisconsin in accordance with the requirements and conditions set forth within Parts I and II of the permit. Please read it carefully. This permit expires 90 months after the day this permit is issued. This source may not operate after this construction permit expires unless you have been issued an operation permit.

Enclosed with the permit there are two copies of a bill for the cost of reviewing and acting upon your air pollution control permit. This bill is due and payable within 30 days of the date of the issuance of the permit. Your check should be made payable to Wisconsin Department of Natural Resources and returned to the address on the bill. Please include one copy of the bill with your payment.

A copy of this permit should be available at the source for inspection by any authorized representative of the Department. Questions about this permit should be directed to the Wisconsin Department of Natural Resources, Wisconsin Department of Natural Resources, Southeast Region, 2300 North Dr. Martin Luther King Jr. Drive, Milwaukee, WI 53212, Phone (414) 263-8500

NOTICE OF APPEAL RIGHTS

If you believe that you have a right to challenge this decision, you should know that Wisconsin statutes establish time periods within which requests to review Department decisions must be filed.

To request a contested case hearing pursuant to s. 285.81, Stats., you have 30 days after the decision is mailed, or otherwise served by the Department, to serve a petition for a contested case hearing on the Secretary of the Department of Natural Resources. Any such petition for hearing shall set forth specifically the issues sought to be reviewed, the interest of the petitioner, the reasons why a hearing is warranted and the relief desired.

For judicial review of a decision pursuant to ss. 227.52 and 227.53, Stats., you have 30 days after the decision is mailed, or otherwise served by the Department, to file your petition with the appropriate circuit court and serve the petition on the Department. Such a petition for judicial review shall name the Department of Natural Resources as the respondent.

This notice is provided pursuant to s. 227.48(2), Stats.

STATE OF WISCONSIN
DEPARTMENT OF NATURAL RESOURCES

Raj Vakharia, Review Engineer
Permits & Stationary Source Modeling Section
Bureau of Air Management

cc: SER Air Program Air Program
SER, Sturtevant Service Center Air Program
US EPA Region V
Kathy Zuelsdorff, PSC, 610 N. Whitney Way, P.O. Box 7854, Madison, WI 53707-7854

Enclosure

BEFORE THE DEPARTMENT OF NATURAL RESOURCES
AIR MANAGEMENT PROGRAM
FINDINGS OF FACT
CONCLUSIONS OF LAW
AND DECISION

Findings of Fact

The Department of Natural Resources (DNR) finds that:

1) Elm Road Generating Station (Referred as North Site with Accommodations), 4801 E. Elm Road, Oak Creek, Wisconsin, Wisconsin has applied for an air pollution control construction permit. The authorized representative of the facility is Scott A. Patulski – Vice President, Fossil Operations.

2) Elm Road Generating Station (Referred as North Site with Accommodations), submitted an air pollution control permit application and plans and specifications and any additional information describing the air contaminant source between June 18, 2002 and January 9, 2004.

3) DNR has reviewed Elm Road Generating Station (Referred as North Site with Accommodations)'s air permit application and the plans and specifications submitted to DNR.

4) This permit is for an air contaminant source.

5) DNR has complied with the procedures set forth in s. 285.61, Stats.

6) The proposed air contaminant source meets all of the applicable criteria in s. 285.63, Stats.

7) DNR has complied with the requirements of s. 1.11, Stats., and ch. NR 150, Wis. Adm. Code.

Conclusions of Law

DNR concludes that:

1) DNR has authority under s. 285.11(a), Stats., to promulgate rules contained in chs. NR 400-499, Wis. Adm. Code, including, but not limited to, rules containing emission limits, compliance schedules and compliance determination methods.

2) DNR has the authority under ss. 285.11(a), (e), and (f), 285.27 and 285.65, Stats., and chs. NR 400-499, Wis. Adm. Code, to establish emission limits for sources of air pollution.

3) DNR has the authority to issue air pollution control permits and to include conditions in such permits under ss. 285.60, 285.61, 285.63 and 285.65, Stats.

4) The emission limits included in this permit are authorized by ss. 285.65, Stats., and NR 400-499, Wis. Adm. Code.

5) DNR is required to comply with s. 1.11, Stats., and ch. NR 150, Wis. Adm. Code, in conjunction with issuing an air pollution control permit.

Decision

Elm Road Generating Station (Referred as North Site with Accommodations), is authorized to construct and initially operate an Electric Generating Facility referred at 4801 E. Elm Road, Oak Creek, Wisconsin, as described in the plans and specifications dated between June 18, 2002 and January 9, 2004 in conformity with the emission limits, monitoring, recordkeeping and reporting requirements and specific and general conditions set forth in this permit.

AIR POLLUTION CONTROL CONSTRUCTION PERMIT

EI FACILITY NO. PERMIT NO. 03-RV-166

STACK NO.(S). S18 –S174 SOURCE NO.(S). B18, B19, B20,P62, P63, P64, P175, P76P, P41, P42, P43, B44, T16, T188, T121, T122, T123, T119, T120

THIS CONSTRUCTION PERMIT EXPIRES NINETY (90) MONTHS FROM THE DATE OF ISSUANCE OR WHEN THE OPERATION PERMIT IS ISSUED FOR THE EMISSION UNITS INCLUDED IN THIS PERMIT, WHICHEVER COMES FIRST.

In compliance with the provisions of Chapter 285, Wis. Stats., and Chapters NR 400 to NR 499, Wis. Adm. Code,

Name of Source: Elm Road Generating Station (Referred as North Site with Accommodations)

Street Address: 4801 E. Elm Road
Oak Creek, Milwaukee County, Wisconsin

Responsible Official & Title: Scott A. Patulski – Vice President, Fossil Operations

is authorized to construct and initially operate an Electric Generating Facility described in the plans and specifications submitted between June 18, 2002 and January 9, 2004 in conformity with the conditions herein.

This authorization requires compliance by the permit holder with the emission limitations, monitoring requirements and other terms and conditions set forth in Parts I and II hereof.

Dated at Madison, Wisconsin this 14th day of Januray 2004.

STATE OF WISCONSIN
DEPARTMENT OF NATURAL RESOURCES
For the Secretary

By signed by Lloyd L. Eagan
Lloyd L. Eagan, Director
Bureau of Air Management

PART I: APPLICABLE LIMITATIONS

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.018 pound per million Btu heat input averaged over any consecutive 3–hour period. (Best Available Control Technology, BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08(2), Wis. Adm. Code, s. NR 440.20(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[1] [s. NR 439.07, Wis. Adm. Code] (2) Stack Parameters: These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 550 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 27 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse system in combination with a flue gas desulfurization and a wet electrostatic precipitator to meet the BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a).1, Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.A.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) The permittee shall perform the compliance emission tests required under condition I.A.1.b.(1) every 24 months within 60 days from the date of the last stack test as long as the permit remains valid. [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5 or 5B including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code; s. NR 440.20(8)(b)2., Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system at the beginning of each operating shift. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) The permittee shall continuously monitor the operating pressure drop across the fabric filter system and shall sound an audible alarm, whenever the operating pressure drop is below minimum pressure drop identified in I.A.1.b.(5) is exceeded. [s. NR 439.055(1)(b)1., Wis. Adm. Code] (6) The permittee shall respond to every "out of range" pressure drop alarm in accordance with the provisions of 40 CFR 64.7(d)(1). [s. 285.65(3), Wis. Stats.] (7) The permittee shall install, calibrate, maintain, and continuously operate a fabric filter bag leak detection system and be equipped with an audible alarm. [s. 285.65(3), Wis. Stats.] (8) The alarm set point and alarm delay time for each bag leak detection system shall be established during the initial testing period. [s. 285.65(3), Wis. Stats.]

Note 1:The boiler is subject to New Source Performance Standards (NSPS) requirements for particulate matter under s. NR 440.20(3), Wis. Adm. Code and is 0.03 pound per million Btu and 99% reduction when combusting solid fuel. The BACT limit for particulate matter is more restrictive then the particulate matter emission limits under NSPS, thus the boiler is expected to meet the particulate matter emission limits under NSPS.

[1] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. **S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2** The following emission limits apply to each SCPC boiler.	
Pollutant: 1. Particulate Matter Emissions [CONTINUED]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(8) The permittee shall comply with the NSPS compliance determination procedures and methods per s. NR 440.20(6), Wis. Adm. Code and s. NR 440.20(8), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.]	(9) The permittee shall record the output of the fabric filter bag leak detection system. [s. 285.65(3), Wis. Stats.] (10)The permittee shall respond to every bag leak detection alarm in accordance with the provisions of 40 CFR 64.7(d)(1). [s. 285.65(3), Wis. Stats.] (11) The permittee shall comply with the NSPS reporting requirements per s. NR 440.20(9), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.]

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 2. Particulate Matter Emissions less than 10 microns (PM_{10})	
a. Limitations: 0.018 pound per million Btu heat input averaged over any consecutive 3–hour period. (BACT) [s. NR 405.08(2), Wis. Adm. Code and s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[1] [s. NR 439.07, Wis. Adm. Code] (2) <u>Stack Parameters:</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 550 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 27 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a).1, Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.A.2.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) The permittee shall perform the compliance emission tests required under condition I.A.2.b.(1) every 24 months within 60 days from the date of the last stack test as long as the permit remains valid. [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Particulate Matter Emissions:</u> Whenever compliance emission testing is required, US EPA Method 5 or 5B including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code; s. NR 440.20(8)(b)2., Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system at the beginning of each operating shift. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) The permittee shall continuously monitor the pressure drop across the fabric filter system and shall sound an audible alarm, whenever the operating pressure drop is below the minimum pressure drop identified in I.A.2.b.(5) is exceeded. [s. NR 439.055(1)(b)1., Wis. Adm. Code] (6) The permittee shall respond to every “out of range” pressure drop alarm in accordance with the provisions of 40 CFR 64.7(d)(1). [s. 285.65(3), Wis. Stats.] (7) The permittee shall install, calibrate, maintain, and continuously operate a fabric filter bag leak detection system and be equipped with an audible alarm. [s. 285.65(3), Wis. Stats.] (8) The alarm set point and alarm delay time for each bag leak detection system shall be established during the initial testing period. [s. 285.65(3), Wis. Stats.] (9) The permittee shall record the output of the fabric filter bag leak detection system. [s. 285.65(3), Wis. Stats.] (10)The permittee shall respond to every bag leak detection alarm in accordance with the provisions of 40 CFR 64.7(d)(1). [s. 285.65(3), Wis. Stats.]

1 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. **S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2** The following emission limits apply to each SCPC boiler.	
Pollutant: 1. Particulate Matter Emissions less than 10 microns (PM_{10}) [CONTINUED]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(8) The permittee shall comply with the NSPS compliance determination procedures and methods per s. NR 440.20(6), Wis. Adm. Code and s. NR 440.20(8), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.]	(11) The permittee shall comply with the NSPS reporting requirements per s. NR 440.20(9), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.]

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 3. Sulfur Dioxide	
a. Limitations: (1) 0.15 pound per million Btu heat input for all periods, including startup and shut down, averaged over any consecutive 30-day period. (BACT) (2) Uncontrolled sulfur dioxide emission rate in the coal shall be limited to 4.0 pound per million Btu, averaged over any consecutive 30-day period. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.20(4), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation. [s. NR 439.07, Wis. Adm. Code] (2) Sulfur Dioxide Emissions shall be controlled by the use of wet flue gas desulfurization (FGDS) System to meet the BACT emission limits. [s. NR 405.08(2), Wis. Adm. Code] (3) The absorber recirculation (AR) slurry flow rate to the wet flue gas desulfurization (FGD) system shall be periodically monitored and maintained within the range specified under condition I.A.3.c.(4). [s. 285.65(3), Wis. Stats.] (4) (a) The boiler may be fired on coal and/or coal/ash fuel blend, except during periods of start-up and load stabilization when natural gas and/or low sulfur fuel oil may also be utilized as a fuel. (b) The amount of ash fired in the boiler may not exceed 5% by weight averaged over any consecutive 30 day period. [s. NR 405.08(2), Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (5) (a) The permittee shall demonstrate compliance with the coal sulfur limit in I.A.3.a,(2)] by utilizing coal sampling and analysis of the coal as it is shipped from the mine. (b) The permittee shall provide the sampling and analysis protocol at least four months prior to the initial operation of the boiler to the Department for approval. (c) In the event that mine sampling and analysis is unavailable, the permittee shall use as received fuel sampling and analysis procedures in accordance with s. NR 439.08, Wis. Adm. Code to demonstrate compliance with this limit. (d) In lieu of fuel sampling and analysis, the permittee may demonstrate compliance with the coal sulfur limit in I.A.3.a.(2) by using emissions data measured by a continuous emission monitoring system at the inlet to the FGD system. [s. 285.65(3), Wis. Stats., s. NR 439.08, Wis. Adm. Code]	(1) <u>Reference Test Method for Sulfur Dioxide Emissions:</u> Whenever compliance emission testing is required, US EPA Method 6, 6A or 6C shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(2), Wis. Adm. Code] (2) (a) The permittee shall install, calibrate, maintain and operate a continuous emission monitoring system, and record the output of the system, for measuring the sulfur dioxide and oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide emissions are monitored. (b) Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 75, s. NR 440.20(7)(b), Wis. Adm. Code and s. NR 439.06(4), Wis. Adm. Code. [s. 285.65(10), Wis. Stats.] (3) The permittee shall use continuous emission monitoring methods and procedures under s. NR 440.20(7)(b), Wis. Adm. Code and s. NR 439.09, Wis. Adm. Code to comply with the NSPS monitoring requirements. [s. NR 439.09, Wis. Adm. Code] (4) The permittee shall provide to the department, at least 4 months prior to the expiration of the construction permit, information on the operational absorber recirculation (AR) slurry flow rate to the FGD system to be used for monitoring the absorber recirculation (AR) slurry flow rate to the FGD system, as required under condition I.A.3.b.(2), and shall incorporate this information into the Malfunction Prevention and Abatement Plan. (MPAP) [s. 285.65(10), Wis. Stats.] (5) The permittee shall submit quarterly reports to the Department on the information required under condition I.A.3.b.(5) for each train of coal received during the calendar quarter. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

Note 1: The proposed boiler is subject to NSPS requirement for sulfur dioxide under s. NR 440.20(4), Wis. Adm. Code. The NSPS limit for sulfur dioxide varies depending upon fuel sulfur content, with either a 90% reduction and 1.2 pound per million Btu limitations or a 70% reduction when emissions are below 0.60 pound per million Btu. The NSPS limits apply at all times except during periods of startup, shut down or when emergency conditions exist and the procedures under s. NR 440.20(6)(d), Wis. Adm. Code is implemented. The BACT limits for sulfur dioxide is more restrictive then the sulfur dioxide emission limits under NSPS, thus the boiler is expected to meet the sulfur dioxide emission limits under NSPS.

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler. [CONTINUED]

Pollutant: 3. Sulfur Dioxide (continued)

b. Compliance Demonstration:	c. Test Methods, Recordkeeping, and Monitoring:
(6) The permittee shall demonstrate compliance with the sulfur dioxide emission limits contained in I.A.3.a. (1) Using emissions data measured by the continuous emission monitoring system required by I.A.3.c. (2) as follows: (a) Daily average concentration shall be calculated each calendar day by combining the sulfur dioxide concentration and diluent concentration (in % O2 or % CO2) measurement consistent with the procedures specified in 40 CFR Part 75 Appendix F. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (7) The permittee shall perform the compliance emission tests required under condition I.A.3.b.(1) every 24 months within 60 days from the date of the last stack test as long as the permit remains valid. [s. NR 439.075(3)(b) Wis. Adm. Code] (8) The permittee shall comply with the NSPS compliance determination procedures and methods per s. NR 440.20(6), Wis. Adm. Code and s. NR 440.20(8), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.] (9) (a) Sulfur dioxide emissions shall be limited to 1,150 pounds per hour averaged over any consecutive 3-hour period and sulfur dioxide emissions shall be limited to 1,050 pounds per hour averaged over any consecutive 24-hour period. These conditions are established to ensure compliance with PSD increments and NAAQS. At these emission rates the air quality standards are expected to be protected. [s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] (b) The permittee shall use the CEMs data to demonstrate compliance with permit condition I.A.3.b. (9)(a). [s. 285.65(3), Wis. Stats.]	(6) The permittee shall comply with the NSPS reporting requirements per s. NR 440.20(9), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.] (7) The permittee shall keep appropriate records to comply with permit condition I.A.3.b. (9). [s. 285.65(3), Wis. Stats.] (8) The permittee shall keep appropriate records to ensure compliance with permit condition I.A.3.b.(4)(b). [s. 285.65(3), Wis. Stats.]

A. **S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler** The following emission limits apply to each SCPC boiler.	
Pollutant: 4. Oxides of Nitrogen (NOx)	
a. Limitations: (1) 0.07 pound per million Btu heat input during normal operation not including periods of startup and shut down, averaged over any consecutive 30-day period. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]; (2) 0.07 pound per million Btu heat input for all periods including startup and shut down, averaged over any consecutive 12-month period. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.20(5)a.1., Wis. Adm. Code, s. 285.65(3), Wis. Stats.] See Notes 1, 2, 3	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.2 [s. NR 439.07, Wis. Adm. Code] (2) Nitrogen Oxide Emissions shall be controlled using low NOx burners, good combustion practices and a Selective Catalytic Reduction (SCR) System to meet the BACT emission limits. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) The permittee shall demonstrate compliance with the NOx emission limit as follows: (a) NOx emissions shall be calculated based on each 24-hour calendar period. (b) 24 hour emissions shall be calculated by combining the NOx concentration and diluent concentration (in % O2 or % CO2) measurement consistent with the procedures specified in 40 CFR Part 75 Appendix F. (c) 12 consecutive months concentrations shall be calculated based on the calculations of the daily concentrations. [s. 285.65(3), Wis. Stats.] (4) The permittee shall maintain the ranges of the parameters identified in condition I.A.4.c.(5)a.-d., to meet good combustion practices and/or maintain proper operation of the SCR. [s. 285.65(3), Wis. Stats.] (5) The permittee shall perform the compliance emission tests required under condition I.A.4.b.(1) every 60 months within 60 days from the date of the last stack test as long as the permit remains valid. [s. NR 439.075(3)(b) Wis. Adm. Code]	(1) <u>Reference Test Method for Nitrogen Oxide Emissions:</u> Whenever compliance emission testing is required, US EPA Method 7 or an alternate method approved in writing by the Department shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(6), Wis. Adm. Code] (2) The permittee shall install and operate continuous emissions monitoring systems (CEMs) for NOx and carbon dioxide or oxygen within 60 days after initial start up of the boiler. The CEMs shall be calibrated within 90 days after initial start up of the boiler. Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 75, s. NR 440.20(7)(d), Wis. Adm. Code and s. NR 439.06(6)(b), Wis. Adm. Code requirements.[s. 285.65(3), Wis. Stats.; s. NR 439.06, Wis. Adm. Code] (3) The permittee shall certify the CEMs in accordance with 40 CFR Part 75 Appendix A. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep appropriate records of the strip chart, round chart or data acquisition (DAS) system/electronic data storage continuously. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (5) During operation, the facility will calculate or continuously monitor and record the unit heat input and the following operating parameters on an hourly basis. a. Furnace outlet temperature, including SCR inlet temperature, ^{o}F b. Secondary Air Flow c. Primary Air Flow d. Fuel Flow Rate e. Residence Time (by calculation only) [s. 285.65(10), Wis. Stats.] (6) During the initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.A.4.c.(5) to establish operational ranges for incorporation into the operation permit. [s. 285.65(10), Wis. Stats] (7) The permittee shall install, calibrate, maintain and operate instrumentation to monitor the parameters identified by condition I.A.4.c.(5)a. - d. [s. 285.65(3) and (10), Wis. Stats.]

2 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. **S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler** The following emission limits apply to each SCPC boiler. [CONTINUED]	
Pollutant: 4. Oxides of Nitrogen [CONTINUED]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(6) The permittee shall comply with the NSPS compliance determination procedures and methods per s. NR 440.20(6), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.]	(8) The permittee shall comply with the NSPS reporting requirements per s. NR 440.20(9), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. 285.65(3), Wis. Stats.] (9) The permittee shall comply with the general and specific monitoring requirements under s. NR 428.04(3)(a) and (b), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (10) The permittee shall comply with all the recordkeeping and reporting requirements under s. NR 428.04(4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(4), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (11) The permittee shall comply with all the requirements for monitoring, installation, certification, data accounting, compliance dates and reporting data prior to initial certification as required under s. NR 428.07(1)(b), Wis. Adm. Code, s. NR 428.07(2)(b)2, Wis. Adm. Code, s. NR 428.07(3), Wis. Adm. Code. [s. 285.65(3), Wis. Stats.] (12) The permittee shall monitor NOx and heat input per s. NR 428.08(1)(a), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (13) The permittee shall submit quarterly reports per s. NR 428.09(1), (3) AND (4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(9), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (14) The permittee shall keep appropriate records to show that the boiler is equipped with low NOx burners. [s. 285.65(3), Wis. Stats.]

Note 1: Startup period begins with the firing of fuel and end when the temperature of the flu gas entering selective catalytic reduction (SCR) system exceeds 650 degrees F. The shut down period begins when the temperature of the flue gas entering SCR system temperature drops below 650 degrees F, and shall end with the cessation of fuel firing. Steady state operation is defined as any hour in which no mills are started or stopped or no stabilization fuel is used in the boiler.

Note 2: The boiler is subject to NSPS requirements under s. NR 440.20(5)(a)1., Wis. Adm. Code for nitrogen oxides. The NSPS limit is 0.50 pound per million Btu. The NSPS emission limits for nitrogen oxides apply at all times except during periods of startup, shut down or malfunction. The BACT limit for nitrogen oxides under I.A.4.a.(1), is more restrictive then the nitrogen oxides emission limits under NSPS, thus the boiler is expected to meet the emission limit for nitrogen oxides under NSPS.

Note 3: The boiler is subject to emission limits for nitrogen oxides under s. NR 428.04(2)(a)1.a., Wis. Adm. Code and is 0.15 pounds per million Btu of heat input on a 30-day rolling average basis. The BACT limit for nitrogen oxides is more restrictive then the nitrogen oxides emissions limit established under s, NR 428,04, Wis. Adm. Code, thus the boiler is expected to meet the nitrogen oxides emission limits under s. NR 428.04, Wis. Adm. Code.

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 5. Carbon Monoxide	
a. Limitations: (1) 0.12 pound per million Btu heat input during steady state operation, excluding periods of startup, shut down and averaged over any consecutive 24-hour period. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65 (7), Wis. Stats.] See Note 1; (2) 742 pounds per hour excluding periods of startup and shut down, averaged over any consecutive 24-hour period. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65 (7), Wis. Stats.]; (3) 2,400 pounds per hour during any one hour period. [s. 285.65(3), Wis. Stats.] See Note 2; (4) 3,250 tons in any 12 consecutive months for all periods, including startup and shut down. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65 (7), Wis. Stats.] See Note 3	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.3 [s. NR 439.07, Wis. Adm. Code] (2)Carbon Monoxide Emissions shall be controlled using low NOx burners and good combustion practices to meet BACT limits. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) The permittee shall demonstrate compliance with the carbon monoxide emission limits as follows: (a) Daily average shall be determined by calculating the arithmetic average of all applicable hourly emission rates for a calendar day. (b) The hourly emission rate shall be calculated by combining the CO concentration and diluent concentration (in % O2 or % CO2) measurement consistent with the procedures specified in 40 CFR Part 75 Appendix F. The conversion factor, (K), shall be 0.7266 x 10E-7 lb CO/ft3 – ppm. (c) The annual emission limit in I.A.5.a.(4) shall be calculated using and totaling the hourly calculated emission rate. [s. 285.65(3), Wis. Stats.] (4) The permittee shall maintain the ranges of the parameters identified in condition I.A.5.c.(3)a.-d., to meet good combustion practices. [s. 285.65(3), Wis. Stats.] (5) The permittee shall perform the compliance emission tests required under condition I.A.5.b.(1) every 60 months within 60 days from the date of the last stack test as long as the permit remains valid. [s. NR 439.075(3)(b) Wis. Adm. Code] (6) The permittee shall keep track of the startup and shut down time by monitoring the temperature of the flue gas entering the SCR. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Carbon Monoxide Emissions: Whenever compliance emission testing is required, US EPA Method 10, or an alternate method approved in writing by the Department shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(4), Wis. Adm. Code] (2) The permittee shall install and operate continuous emissions monitoring systems (CEMs) for CO and oxygen or CO2 within 60 days after initial start up of the boiler. The CEMs shall be calibrated within 90 days after initial start up of the boiler. Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 60 Appendix B, and s. NR 439.06(4), Wis. Adm. Code requirements. [s. 285.65(3), Wis. Stats., s. NR 439.06, Wis. Adm. Code] (3) During operation, the facility will calculate or continuously monitor and record the unit heat input and the following operating parameters on an hourly basis. a. Furnace outlet temperature, ^{o}F b. Secondary Air Flow c. Primary Air Flow d. Fuel Flow Rate e. Residence Time (by calculation only) [s. 285.65(10), Wis. Stats.] (4) During the initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.A.5.c.(3) to establish operational ranges for incorporation into the operation permit. [s. 285.65(10), Wis. Stats.] (5) The permittee shall install, calibrate, maintain and operate instrumentation to monitor the parameters identified by condition I.A.5.c.(3)a.-d. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (6) Continuous emission monitoring methods and procedures shall comply with the requirements of s. NR 439.09, Wis. Adm. Code. [s. NR 439.09, Wis. Adm. Code] (7) The permittee shall keep appropriate records to show that the boiler is equipped with low NOx burners. [s. 285.65(3), Wis. Stats.]

3 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 5. Carbon Monoxide [CONTIUNUED]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
	(8) (a) The permittee shall keep records to show that they did not exceed the emission limit in I.A.5.a.(2), (3) and (4) and condition I.A.5.b.(3). (b) The permittee shall monitor the temperature of the flue gas entering the SCR and keep records of the flue gas temperature entering the SCR to show compliance with Note 1. [s. 285.65(3), Wis. Stats.]

Note 1: Startup period begins with the firing of fuel and end when the temperature of the flu gas entering selective catalytic reduction (SCR) system exceeds 650 degrees F. The shut down period begins when the temperature of the flue gas entering SCR system temperature drops below 650 degrees F, and shall end with the cessation of fuel firing. Steady state operation is defined as any hour in which no mills are started or stopped or no stabilization fuel is used in the boiler.

Note 2: This hourly emission limit is established to protect the ambient air quality standards.

Note 3: This limit is based on a BACT limit, 0.12 pound per million Btu heat input x heat input of the boiler, 6,180 mmBtu/hr x 8,760 hours/year operation x ton/2000 lbs.

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 6. Volatile Organic Compounds (VOC)	
(a) Limitations: (1) 0.0035 pound per million Btu heat input during steady state operation excluding periods of startup and shut down averaged over any consecutive 24-hour period. (LAER) [s. NR 408.04, Wis. Adm. Code, s. 285.65(7), Wis. Stats.] See Note 1; (2) 21.6 pounds per hour excluding periods of startup and shut down, averaged over any consecutive 24-hour period. (LAER) [s. NR 408.04, Wis. Adm. Code, s. 285.65(7), Wis. Stats.] ; (3) 95 tons in any 12 consecutive months for all periods, including startup and shut down. (LAER) [s. NR 408.04, Wis. Adm. Code, s. 285.65(7), Wis. Stats.] See Note 2	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.4 [s. NR 439.07, Wis. Adm. Code] (2) VOC Emissions shall be controlled using low NOx burners and good combustion practices to meet LAER limits. [s. NR 419.03, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) The permittee shall maintain the ranges of the parameters identified in condition I.A.6.c.(2)a.-d., to meet good combustion practices (LAER). [s. 285.65(3), Wis. Stats.] (4) The permittee shall demonstrate compliance with the volatile organic compound emission limit contained in I.A.6.a. as follows: (a) VOC emissions shall be calculated based on each 24-hour calendar period. (b) The permittee shall calculate an hourly average emission rate based on measured data using CO CEMs required in I.A.5.b. (4) by combining the CO concentration and diluent concentration (in %O2 or % CO2) measurement, consistent with the procedures specified in 40 CFR Part 75 Appendix F, in the following equation: VOC actual = VOC limit X (CO actual/CO limit) [s. 285.65(3), Wis. Stats.] (5) The permittee shall provide the following information to the Department for approval at least 4 months prior to the initial operation: (a) Compliance demonstration method that will be used and the records that will be kept to comply with the emission limit in I.A.6.a.(2), and (3). The Department will use this information to write the operation permit. [s. 285.65(3), Wis. Stats.] (6) The permittee shall keep track of the startup and shut down time by monitoring the temperature of the flue gas entering the SCR. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for VOC Emissions: Whenever compliance emission testing is required, US EPA Method 25A and/or 18 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(3), Wis. Adm. Code] (2) During operation, the facility will calculate or continuously monitor and record the unit heat input and the following operating parameters on an hourly basis. a. Furnace outlet temperature, ^oF b. Secondary Air Flow c. Primary Air Flow d. Fuel Flow Rate e. Residence Time (by calculation only) [s. 285.65(10), Wis. Stats.] (3) During the initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.A.6.c.(2) to establish operational ranges for incorporation into the operation permit. [s. 285.65(10), Wis. Stats.] (4) The permittee shall install, calibrate, maintain and operate instrumentation to monitor the parameters identified by condition I.A.6.c.(2)a.-d. [s. 285.65(3) and (10), Wis. Stats.] (5) The permittee shall keep appropriate records to show that the boiler is equipped with low NOx burners. [s. 285.65(3), Wis. Stats.] (6) The permittee shall monitor the temperature of the flue gas entering the SCR and keep records of the flue gas temperature entering the SCR to show compliance with Note 1. [s. 285.65(3), Wis. Stats.]

Note 1: The LAER limit of 0.0035 pound per million Btu heat input equates to 21.6 pounds in any hour at maximum output levels. Startup period begins with the firing of fuel and end when the temperature of the flu gas entering selective catalytic reduction (SCR) system exceeds 650 degrees F. The shut down period begins when the temperature of the flue gas entering SCR system temperature drops below 650 degrees F, and shall end with the cessation of fuel firing. Steady state operation is defined as any hour in which no mills are started or stopped or no stabilization fuel is used in the boiler.

Note 2: This limit is based on a LAER limit, 0.0035 pound per million Btu heat input x heat input of the boiler, 6,180 mmBtu/hr x 8,760 hours/year operation x ton/2000 lbs.

4 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 7. Lead Emissions	
a. Limitations: 7.9 pound per trillion Btu Heat Input. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65 (7), Wis. Stats]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[5] [s. NR 439.07, Wis. Adm. Code] (2) Lead emissions shall be controlled using a fabric filter baghouse system to meet the BACT limit. [s. 285.65(3), Wis. Stats.] (3) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10 and s. NR 407.09(4)(a)1., Wis. Adm. Code] (4) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (5) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.A.7.b.(4). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (6) The permittee shall perform the compliance emission tests required under condition I.A.7.b.(1) every 60 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Lead Emissions:</u> Whenever compliance emission testing is required, US EPA Method 12 or Method 29 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system at the beginning of each operating shift. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

5 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 8. Mercury Emissions	
a. Limitations: 1.12 pound per trillion Btu Heat Input (BACT, MACT) [s. NR 408.04, Wis. Adm. Code, s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.6 [s. NR 439.07, Wis. Adm. Code] (2) Mercury emissions shall be controlled using a fabric filter baghouse system coupled with the use of a FGDs flue gas desulfurization system and SCR to meet the BACT limit. [s. 285.65(3), Wis. Stats.] (3) Compliance demonstration identified earlier in this permit for the baghouse system, section I.A.1, and the FGD flue gas desulfurization system, section I.A.3, and the SCR system, section I.A.4, shall be used as compliance demonstration techniques for mercury emissions as well. [s. 285.65(3), Wis. Stats.] (4) The permittee shall perform 4 stack tests within 18 months of the initial operation and then perform biannual stack test, the first of which shall be performed at the beginning of the initial operation period and every 6 months until the initial operation period has been completed. (b) The permittee shall perform the compliance emission tests required under condition I.A.8.b.(1) every 60 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (5) (a)The permittee shall determine mercury emission through coal sampling and analysis. The permittee shall monitor monthly average mercury content and higher heating value in the coal. (b) The data obtained from the monthly coal sampling and analysis shall be correlated with the results of the latest emission compliance test for the purpose of calculating mercury emission rate. [s. NR 405.08, Wis. Adm. Code] (6) The permittee shall submit the results of the compliance testing to the Department and the Department will review the test results and adjust the emissions limit to more accurate reduction levels for mercury when the operation permit is issued. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Mercury Emissions: Whenever compliance emission testing is required, US EPA Method 29 or an alternative method approved in writing by the department shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system at the beginning of each operating shift. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

Note 1: The BACT emission limit for Mercury is based on uncontrolled mercury emissions of 11.2 pounds per trillion Btu and an control efficiency of 90%. The permittee shall achieve process optimization during the initial operation and conduct stack testing for mercury emissions to determine the mercury reduction that is achieved through the use of fabric filter, Wet FGD and SCR system. The Department will use the testing information to adjust the emissions limit to more accurate reduction levels for mercury when the operation permit is issued.

6 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 9. Emissions of Fluorides	
a. Limitations: 0.00088 pound per million Btu heat input. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65 (7) Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.7 [s. NR 439.07, Wis. Adm. Code] (2) Emissions of fluorides shall be controlled by a fabric filter baghouse system and a FGD system. [s. NR 406.10, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) Compliance demonstration identified earlier in this permit for fabric filter baghouse system and the FGD system, section I.A.3, I.A.1. shall be used as compliance demonstration techniques for fluoride emissions as well. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Emissions of Fluorides:</u> Whenever compliance emission testing is required, US EPA Method 13B shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code]

Pollutant: 10. Visible Emissions	
a. Limitations: 20% opacity or number 1 on the Ringlemann chart. [s. NR 431.05, Wis. Adm. Code, s. NR 440.20(3)(b), Wis. Adm. Code] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Opacity shall be controlled using a fabric filter baghouse system. [s. 285.65(3), Wis. Stats.] (2) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall install, calibrate, maintain and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. [s. NR 440.20(7)(a), Wis. Adm. Code, s. 285.65(10), Wis. Stats.] (3) Continuous opacity monitoring methods and procedures shall comply with the requirements of s. NR 440.20(7)(a), Wis. Adm. Code and s. NR 439.09, Wis. Adm. Code. [s. NR 439.09, Wis. Adm. Code; s. 285.65(3), Wis. Stats.] (4) The continuos opacity monitor (COM) may be located after the baghouse and before the WFGD where condensed water vapor is not present, because the SCPC boilers will utilize wet flue gas desulfurization systems which operate at conditions that will have condensed water vapor present in the flue gas in the stack. [s. 285.65(3), Wis. Stats.]

Note 1: No owner or operator may cause to be discharged into the atmosphere any gases which exhibit greater than 20% opacity (6-minute average), except for one 6-minute period per hour of not more than 27% opacity per s. NR 440.20(3)(b), Wis. Adm. Code.

7 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18 – Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 11. Beryllium	
a. Limitations: 0.35 pound per trillion Btu heat input. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65 (7) Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.8 [s. NR 439.07, Wis. Adm. Code] (2) Emissions of beryllium shall be controlled by a fabric filter baghouse system and a FGD System to meet the BACT limit. [s. NR 406.10, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) Compliance demonstration identified earlier in this permit for fabric filter baghouse system and the FGD system, section I.A.3, I.A.1. shall be used as compliance demonstration techniques for beryllium emissions as well. [s. 285.65(3), Wis. Stats.] (4) The permittee shall perform the compliance emission tests required under condition I.A.11.b.(1) every 60 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (5) The permittee shall monitor beryllium emissions through coal sampling and analysis. The permittee shall monitor monthly average beryllium content and higher heating value in the coal. (b) The data obtained from the monthly coal sampling and analysis shall be correlated with the results of the latest emission compliance test for the purpose of calculating beryllium emission rate. [s. NR 405.08, Wis. Adm. Code]. [s. NR 405.08, Wis. Adm. Code]	(1) Reference Test Method for Emissions of Beryllium: Whenever compliance emission testing is required, US EPA Method 29 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system at the beginning of each operating shift. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

8 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A.S18, B18– Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 12. Hazardous air pollutants (inorganic solid HAPs, inorganic acid HAPs, Organic HAPs) regulated under sec. 112 of the Clean Air Act.	
a. Limitations: (1) The permittee shall use fabric filter baghouse and comply with the PM/PM10 limits in I.A.1.a to meet case by case MACT for inorganic solid HAPs; (2) The permittee shall use a wet flue gas desulfurization system (FGD) and comply with the emission limitation of condition I.A.3.a.(1) to meet case by case MACT limits for inorganic acid HAPs; (3) The permittee shall comply with and meet the VOC emission limits to comply with case by case MACT for organic HAPs [s. 285.65(13), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Inorganic HAPs emission shall be controlled using a fabric filter baghouse system. [s. 285.65(3), Wis. Stats.] (2) The compliance demonstration method identified in section I.A.1.b.(6), shall be used as compliance demonstration techniques for inorganic HAPs emission limitations in I.A.12.a.(1). [s. 285.65(3), Wis. Stats.] (3) Inorganic acid HAPs emission shall be controlled using a wet flue gas desulfurization system (FGD) [s. 285.65(3), Wis. Stats.] (4) The compliance demonstration method identified in section I.A.3.b.(5), shall be used as compliance demonstration techniques for inorganic acid HAPs emission limitations in I.A.12.a. (2). [s. 285.65(3), Wis. Stats.] (5) Organic HAPs emission shall be controlled using good combustion practices. [s. 285.65(3), Wis. Stats.] (6) The compliance demonstration method identified in section I.A.6.b.(2), (3), and (4) shall be used as compliance demonstration techniques for organic HAPs emission limitations in I.A.12.a. (3). [s. 285.65(3), Wis. Stats.] (7) The amount of ash fired in the SCPC boilers may not exceed 5% by weight averaged over any consecutive 30-day period. [s. 285.65(3), Wis. Stats.] (8) The permittee shall analyze the ash fired as fuel at least once a year and any time a different coal is used to ensure the fly ash and bottom ash meet the definition of coal and thus the use of this ash is exempt from the requirements of ch. NR 445, Wis. Adm. Code. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for organic HAPs Emissions; inorganic solid HAPs, and inorganic acid HAPs: Whenever compliance testing is required, a compliance test protocol approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall shall keep appropriate records to demonstrate compliance with permit conditions I.A.12.b.(7) and (8). [s. 285.65(3), Wis. Stats.]

A.S18, B18– Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 13 Ammonia Emissions	
a. Limitations: (1) 5 ppm and 20 pounds per hour9 [s. NR 445.04(1), Wis. Adm. Code]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall demonstrate compliance with applicable ammonia hourly emission limit by performing a stack test using USEPA conditional test Method 027, within 180 days after initial start up of the boiler10. (a) Compliance emission tests shall be conducted at 100% load operation. (b) If operation at the 100% load is not feasible, the source shall operate at a capacity level that is approved by the Department in writing. [s. NR 439.075(3), Wis. Adm. Code] (2) The permittee shall perform the compliance emission tests required under condition I.A.13.b.(1) every 60 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Ammonia: Whenever compliance testing for ammonia is required, USEPA Method 027, or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code]

9 These emissions do not result from combustion. Aqueous ammonia is used as the reagent for the SCR. Ammonia that does not react is exhausted out of the stack.

10 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18– Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2 The following emission limits apply to each SCPC boiler.	
Pollutant: 14. Sulfuric Acid Mist	
a. Limitations: 0.010 pound per million Btu heat input, based upon a 24-hour average. (BACT) [s. NR 405.08(2), Wis. Adm. Code]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.11 [s. NR 439.07, Wis. Adm. Code] (2) Sulfuric acid mist emissions shall be controlled by a FGD system and wet electrostatic precipitator system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (3) The boiler may only be fired on coal and/or ash fuel blend, except for periods of start-up and load stabilization when natural gas or fuel oil may also be utilized as a fuel. [s. NR 405.08(2) , Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (4) The permittee shall perform the compliance emission tests required under condition I.A.14.b.(1) every 60 months from the date of the last stack test as long as the permit remains valid. [s. NR 439.075(3)(b) Wis. Adm. Code] (5) The absorber recirculation (AR) slurry flow rate of water to the FGD system shall be periodically monitored and maintained within the range specified under condition I.A.14.c.(2). [s. 285.65(3), Wis. Stats.] (6) The sulfur content of fuel oil to be used during periods of start-up and load stabilization may not exceed 0.003% by weight. [s. 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (7) During the initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.A.14.c.(5) to establish operational ranges for incorporation into the operation permit. [s. 285.65(10), Wis. Stats.] (8) The permittee shall maintain the ranges of the parameters identified in condition I.A.14.c.(5)a.-d., to meet good combustion practices. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Sulfur Acid Mist Emissions:</u> Whenever compliance emission testing is required, US EPA Method 8 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall provide to the department, at least 4 months prior to the expiration of the construction permit, information on the operational water flow rate to the FGD system to be used for monitoring the flow rate of water to the FGD system, as required under condition I.A.14.b.(7). [s. 285.65(10), Wis. Stats.] (3) Compliance with the fuel oil sulfur requirements of I.A.14.b.(6) shall be determined using periodic sampling and analysis using methods and procedures specified under condition I.A.13.c.(4). [s. NR 439.06(2)(c), Wis. Adm. Code] (4) The sulfur content of a liquid fossil fuel sample shall be determined according to ASTM D129-95, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), ASTM D1552-95, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), or ASTM D4294-98, Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-ray Fluorescence Spectroscopy. [s. NR 439.08(2)(b), Wis. Adm. Code] (5) During operation, the facility will calculate or continuously monitor and record the unit heat input and the following operating parameters on an hourly basis. a. Furnace outlet temperature, ^{o}F b. Secondary Air Flow c. Primary Air Flow d. Fuel Flow Rate e. Residence Time (by calculation only) [s. 285.65(10), Wis. Stats.] (6) The permittee shall install, calibrate, maintain and operate instrumentation to monitor the parameters identified by condition I.A.14.c.(5)a.-d. [s. 285.65(3) and (10), Wis. Stats.]

11 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

A. S18, B18– Super Critical Pulverized Coal (SCPC) Boiler 1; S19, B19 – Super Critical Pulverized Coal (SCPC) Boiler 2
The following emission limits apply to each SCPC boiler.

Pollutant: 15. Hydrogen Chloride

a. Limitations: 16.2 pounds per hour, based upon a 24-hour average (MACT), regulated under sec. 112 of the Clean Air Act. [s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation. [s. NR 439.07, Wis. Adm. Code] (3) Hydrogen Chloride emissions shall be controlled by the use of wet flue gas desulfurization (FGDS) Systems to meet the MACT limits. [s. NR 405.08(2), Wis. Adm. Code] (3) The boiler may only be fired on coal and/or ash fuel blend, except for periods of start-up and load stabilization when natural gas or fuel oil may also be utilized as a fuel. [s. NR 405.08(2) , Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (4) The permittee shall perform the compliance emission tests required under condition I.A.15.b.(1) every 60 months from the date of the last stack test as long as the permit remains valid. [s. NR 439.075(3)(b) Wis. Adm. Code] (5) The absorber recirculation (AR) slurry flow rate of water to the FGD system shall be periodically monitored and maintained within the range specified under condition I.A.15.c.(2). [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Hydrogen Chloride Emissions:</u> Whenever compliance emission testing is required, US EPA Method 26A shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall provide to the department, at least 4 months prior to the expiration of the construction permit, information on the operational absorber recirculation (AR) slurry flow rate to the FGD system to be used for monitoring the absorber recirculation (AR) slurry flow rate to the FGD system, as required under condition I.A.15.b.(3), and shall incorporate this information into the Malfunction Prevention and Abatement Plan. [s. 285.65(10), Wis. Stats.] (3) Instrumentation to monitor the absorber recirulation (AR) slurry flow rate to the wet flue gas desulfurization (FGD) system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

B. S20, B20 – SCPC Auxiliary Boiler	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: (1) The emissions may not exceed 0.007 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.05 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation when firing distillate fuel oil.[12] [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall determine the hourly emissions using fuel consumption records and emissions factor determined by stack testing. [s. 285.65(3), Wis. Stats.] (3) <u>Stack Parameters</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 280.0 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 5.0 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (4) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight . This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (6) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.1.a. (4). [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Particulate Matter Emissions:</u> Whenever compliance emission testing is required, test procedures in 40 CFR 60, Appendix A, Reference Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall keep records on the heat input used as required in condition I.B.1.b.(6). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) The permittee shall record information on the maintenance required in condition I.B.1.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

Note 1: The boiler is subject to NSPS requirements under s. NR 440.205, Wis. Adm. Code for particulate matter. The only New Source Performance Standards (NSPS) standard that will be applicable to the boiler for PM is in the form of an opacity standard when fuel oil is fired per 40 CFR Part 60.43b(f) and s. NR 440.205(4) (f), Wis. Adm. Code.

12 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

B. S20, B20 – SCPC Auxiliary Boiler	
Pollutant: 2. Particulate Matter Emissions less than 10 microns (PM_{10})	
Limitations: (1) The emissions may not exceed 0.007 pound per million Btu when firing natural gas. (BACT).; (2) The emissions may not exceed 0.05 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.13 [s. NR 439.07, Wis. Adm. Code] (1) The permittee shall determine the hourly emissions using fuel consumption records and emissions factor determined by stack testing. [s. 285.65(3), Wis. Stats.] (3) Stack Parameters: These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 280 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 5.0 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (4) The permittee shall fire natural gas and/or fuel having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (6) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.2.a. (4). [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall keep records on the heat input used as required in condition I.B.2.b.(6). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) The permittee shall record information on the maintenance required in condition I.B.2.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

13 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

B. S20, B20 – SCPC Auxiliary Boiler	
Pollutant: 3. Sulfur Dioxide	
a. Limitations: (1) The emissions may not exceed 0.0024 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.0032 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records, fuel sulfur content and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight . This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for Sulfur Dioxide Emissions:</u> Whenever compliance emission testing is required, US EPA Method 6, 6A or 6C shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(2), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.B.3.b.(8). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.B.3.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

Note 1: The sulfur dioxide New Source Performance Standard (NSPS) in Subpart Db and s. NR 440.205(3), Wis. Adm. Code will be applicable to the boiler only when fuel oil is fired. Based on vendor specification for fuel oil and the proposed BACT limits, the sulfur percentage of the fuel will not exceed 0.05% by weight. Thus it meets the definition for "very low sulfur fuel oil" given in 40 CFR 60.41 and s. NR 440.205(2)(zj), Wis. Adm. Code. Affected sources combusting only very low sulfur fuel oil are not subject to percent reduction requirements required under 40 CFR 60.42(a) per s. NR 440.205(3)(j), Wis. Adm. Code. Also, facilities that combust very low sulfur fuel oil are not required to conduct performance testing or install and operate continuous monitors for sulfur dioxide and if fuel receipts are maintained.

B. S20, B20 – SCPC Auxiliary Boiler	
Pollutant: 3. Sulfur Dioxide (continued)	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(4) A representative sample shall be taken from each fuel lot of fuel oil received. The sample shall be analyzed by the permittee for the sulfur content by weight using procedures outline in s. NR 439.08(2), Wis. Adm. Code and the analysis shall be retained by the permittee for a period of at least five years. [s. 285.65(3), Wis. Stats.] (5) The Department will accept, in lieu of an analysis on each fuel lot under (4) above, an analysis of a representative sample of the fuel lot of distillate fuel oil from which the fuel lot was taken. [s. 285.65(3), Wis. Stats.] (6) The permittee shall retain copies of its distillate fuel oil supplier's fuel sulfur and heat content analyses at the facility for each fuel lot of distillate fuel oil received pursuant to 40 CFR 60.334 for a period of five years. [s. NR 439.04(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (7) The permittee shall further obtain certification from the fuel supplier that the applicable methods in s. NR 439.08(2), Wis. Adm. Code, were followed, if applicable, by the supplier in the preparation of said sulfur and heat content analyses. The fuel lot's quantity of fuel oil shall be included with the copies of these analyses. [s. 285.65(3), Wis. Stats.] (8) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.3.a. (4). [s. 285.65(3), Wis. Stats.]	(5) The permittee shall keep records required under condition I.B.3.b.(4) – (7). [s. NR 439.04(1)(d), Wis. Adm. Code] (6) The permittee shall obtain and maintain fuel receipts from the fuel supplier which certify that the fuel oil meets the definition of distillate oil as defined in s. NR 440.205(2)(h), Wis. Adm. Code, if the permittee combust very low sulfur fuel oil as defined under s. NR 440.205(2)(zj), Wis. Adm. Code. A copy of the requirements attached with the permit. [s. NR 440.205(3)(j)2., Wis. Adm. Code, s. 285.65(7), Wis. Stats.] (7) The permittee shall submit quarterly reports to the Department certifying that only very low sulfur fuel oil meeting the definition was combusted in the affected facility during the preceding quarter. [s. 285.65(7), Wis. Stats., s. NR 440.205(10)(r), Wis. Adm. Code.]

<table>
<tr><th colspan="2">B. S20, B20 – SCPC Auxiliary Boiler</th></tr>
<tr><td colspan="2">Pollutant: 4. Oxides of Nitrogen</td></tr>
<tr><td colspan="2">a. Limitations: (1) The emissions may not exceed 0.036 pound per million Btu when firing natural gas based on a 30-day rolling average. (BACT); (2) The emissions may not exceed 0.09 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight oil based on a 30-day rolling average. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months.[s. NR 405.08(2), Wis. Adm. Code, s, NR 428.04(2)(a)2. and 3., s. NR 428.04(2)(a)2. and 3., s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) The permittee shall determine the hourly emissions using fuel consumption record and vendors or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s, 285.65(10), Wis. Stats.]

(4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.4.a. (4). [s. 285.65(3), Wis. Stats.]

(5) The permittee shall determine compliance with the emission limits in I.B.4.a.(2) by conducting performance test as required under s. NR 440.08, Wis. Adm. Code using one the continuous systems for monitoring nitrogen oxides under s. NR 440.205(9)(g), Wis. Adm. Code as follows:
(a) Comply with the provisions of s. NR 440.205(9)(b), (c), (d), (e) 2., (e) 3., and (f), or
(b) Monitor steam generating unit operating conditions and predict nitrogen oxides emission rates as specified in a plan submitted pursuant to s. NR 440.205(10)(c), Wis. Adm. Code.
(c) Submit a plan as required under s. NR 440.205(10)(c) to the Department for approval within 360 days of the initial startup of the facility. [s. 285.65(3), Wis. Stats.]</td><td>(1) <u>Reference Test Method for Nitrogen Oxide Emissions:</u> Whenever compliance emission testing is required, test procedures in 40 CFR 60, US EPA Method 7 or an alternate method approved in writing by the Department shall be used to demonstrate compliance.
[s. NR 439.06(6), Wis. Adm. Code]

(2) The permittee shall keep records on the heat input used as required in condition I.B.4.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.B.4.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

(5) The permittee shall maintain records of the information required under s. NR 440.205(1)(g), Wis. Adm. Code. A copy of the requirements attached with this permit. [s. 285.65(3), Wis. Stats.]

(6) The permittee shall submit quarterly reports containing the information recorded in (5) above to the Department for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. [s. 285.65(3), Wis. Stats., s. NR 440.205(10)(I), Wis. Adm. Code]</td></tr>
</table>

Note 1: The boiler will have high heat release rate and therefore subject to New Source Performance Standards (NSPS) emission limit of 0.20 pound per million Btu on a 30 day rolling average per s. NR 440.205(5)(a)1.b., Wis. Adm. Code for NOx. The proposed BACT emission limit for NOx is more restrictive then the NSPS limit for NOx.

Note 2: The boiler is subject to s. NR 428.04(2)(a)2. and 3., Wis. Adm. Code and is 0.05 pounds per million Btu of heat input when firing natural gas and 0.09 pounds per million Btu of heat input when firing fuel oil for NOx. The BACT limit for NOx is more restrictive or equal to the NOx limit established under s. NR 428,04, Wis. Adm. Code, thus the boiler is expected to meet the limits for NOx emission limits under s. NR 428.04, Wis. Adm. Code.

B. S20, B20 – SCPC Auxiliary Boiler	
Pollutant: 4. Oxides of Nitrogen [CONTINUED]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
	(8) The permittee shall comply with the general and specific monitoring requirements under s. NR 428.04(3)(a) and (b), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (9) The permittee shall comply with all the recordkeeping and reporting requirements under s. NR 428.04(4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(4), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (10) The permit shall comply with all the requirements for monitoring, installation, certification, data accounting, compliance dates and reporting data prior to initial certification as required under s. NR 428.07(1)(b), Wis. Adm. Code, s. NR 428.07(2)(b)2, Wis. Adm. Code, s, NR 428.07(3), Wis. Adm. Code. [s. 285.65(3), Wis. Stats.] (11) The permittee shall monitor NOx and heat input per s. NR 428.08(1)(c), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (12) The permittee shall submit quarterly reports per s. NR 428.09(1), (3) and (4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(9), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

B. S20, B20 – SCPC Auxiliary Boiler	
Pollutant: 5. Carbon Monoxide	
a. Limitations: (1) The emissions may not exceed 0.075 pound per million Btu when firing natural gas based on a 30-day rolling average. (BACT); (2) The emissions may not exceed 0.075 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight based on a 30-day rolling average. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 factor or vendor provided emissions factor [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and /or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.5.a. (4). [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Carbon Monoxide Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR Part 60, US EPA Method 10, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(4), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.B.5.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.B.5.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

B. S20, B20 – SCPC Auxiliary Boiler	
Pollutant: 6. Volatile Organic Compounds (VOC)	
a. Limitations: (1) The emissions may not exceed 0.0060 pound per million Btu when firing natural gas based on a 30-day rolling average. (LAER); (2) The emissions may not exceed 0.0050 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight based on a 30-day rolling average. (LAER); (3) The use of good combustion practices. (LAER); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 408.04, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor or vendor provided emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet LAER emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.6.a. (4). [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for VOC Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR Part 60, US EPA Method 25 or 18, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(3), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.B.6.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.B.6.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

B. S20, B20 – SCPC Auxiliary Boiler	
Pollutant: 7. Lead Emissions	
a. Limitations: (1) The emissions may not exceed 0.000000024 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.000009 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.7.a. (4). [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Lead Emissions:</u> Whenever compliance emission testing is required, US EPA Method 12 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.B.7.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.B.7.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

B. S20, B20 – SCPC Auxiliary Boiler	
Pollutant: 8. Mercury Emissions	
a. Limitations: (1) The emissions may not exceed 0.00000026 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.000003 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu in any 12 consecutive months, of which no more than 122,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.8.a. (4). [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Mercury Emissions:</u> Whenever compliance emission testing is required, US EPA Method 29 or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.B.8.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.B.8.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

B. S20, B20 – SCPC Auxiliary Boiler	
Pollutant: 9. Emissions of Fluorides	
a. Limitations: (1) The emissions may not exceed 0.027 pound per million Btu when firing natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (2) The use of good combustion practices. (BACT); (3) The total heat input may not exceed 498,000 mmBtu on a 12-month rolling average, of which no more than 122,500 mmBtu may be from the combustion of fuel oil on a 12-month rolling average. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.9.a. (3). [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Emissions of Fluorides: Whenever compliance emission testing is required, US EPA Method 13B shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.B.9.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.B.9.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

Pollutant: 10. Visible Emissions	
a. Limitations: 20% opacity or number 1 on the Ringlemann chart. [s. NR 431.05, Wis. Adm. Code, s. NR 440.205(4)(f), Wis. Adm. Code] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (2) The permittee shall conduct an initial test as required under s. NR 440.08, Wis. Adm. Code using the procedures and reference method in 40 CFR part 60, Appendix A, which is incorporated by reference in s. NR 440.17, Wis. Adm. Code. [s. NR 440.205(7)(d), Wis. Adm. Code]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

Note 1: Any gases emitted from the stack when the unit is fired with fuel oil shall not have an opacity greater than 20% (6 minutes average). The exception is one 6-minute period per hour when the opacity not exceeding 27%. The opacity standard does not apply during periods of start up and shut down or malfunction per s. NR 440.025(4)(f), Wis. Adm. Code.

<table>
<tr><td colspan="2">B. S20, B20 – SCPC Auxiliary Boiler</td></tr>
<tr><td colspan="2">Pollutant: 11. Hazardous air pollutants (inorganic solid HAPs, inorganic acid HAPs, Organic HAPs) regulated under sec. 112 of the Clean Air Act.</td></tr>
<tr><td colspan="2">a. Limitations: (1) The permittee shall use natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight and comply with the PM/PM10 limits to meet case by case MACT for inorganic solid HAPs; (2) The permittee shall us natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight to comply with the case by case MACT limits for inorganic acid HAPs; (3) The permittee shall comply with and meet the VOC LAER emission limits to comply with case by case MACT for organic HAPs and (4) The total heat input may not exceed 498,000 mmBtu on a 12-month rolling average, of which no more than 122,500 mmBtu may be from the combustion of fuel oil on a 12-month rolling average. [s. 285.65(13), Wis. Stats.]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire natural gas and/or 0.003% by weight low sulfur fuel oil. This condition is established to meet MACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.11.a. (4). [s. 285.65(3), Wis. Stats.]</td><td>(1) <u>Reference Test Method for organic HAPs Emissions; inorganic solid HAPs, and inorganic acid HAPs:</u> Whenever compliance emission testing is required a method approved in writing by the Department shall be used to demonstrate compliance.
[s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep records on the heat input used as required in condition I.B.11.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.B.11.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]</td></tr>
</table>

B. S20, B20 – SCPC Auxiliary Boiler	
Pollutant: 12. Sulfuric Acid Mist	
a. Limitations: (1) The emissions may not exceed 0.00024 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.00064 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 498,000 mmBtu on a 12-month rolling average, of which no more than 122,500 mmBtu may be from the combustion of fuel oil on a 12-month rolling average. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (2) The permittee shall determine the hourly emissions using fuel consumption records, and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (3) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.B.12.a. (4). [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Sulfur Acid Mist Emissions:</u> Whenever compliance emission testing is required, US EPA Method 8 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] 2) The permittee shall keep records on the heat input used as required in condition I.B.12.b.(3). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall keep records required under condition I.B.3.b.(4) – (7) to demonstrate compliance with the sulfur content in the fuel. [s. NR 439.04(1)(d), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2 The following emission limits apply to each Diesel Generator.	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: (1) The emissions may not exceed 1.94 pounds per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive month period.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight . (BACT); (4) The use of good combustion practices (BACT).; (5) The emissions unit may be operated only during the hours from 9:00 am to 1:00 PM. This condition is established to protect the ambient air quality standards. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation when firing natural gas and fuel oil.14 [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall determine the hourly emissions using operating parameters and certified test data as required by 40 CFR Part 60. [s. 285.65(3), Wis. Stats.] (3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 18 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 2.12 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (4) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight . This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR 60, Appendix A and US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code)] (3) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.1.a.(2). [s. 285.65(10), Wis. Stats., 285.65(3), Wis. Stats.] (4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) The permittee shall record information on the maintenance required in condition I.C.1.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code] (6) The permittee shall record the start and end times of the diesel generator operation to demonstrate compliance with condition I.C.1.a.(5). [s. 285.65(3), Wis. Stats.]

14 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2 **The following emission limits apply to each Diesel Generator.**	
Pollutant: 2. Particulate Matter Emissions less than 10 microns (PM_{10})	
a. Limitations: (1) The emissions may not exceed 1.94 pounds per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) (5) The emissions unit may be operated only during the hours from 9:00 am to 1:00 PM. This condition is established to protect the ambient air quality standards. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.15 [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall determine the hourly emissions using operating parameters and certified test data as required by 40 CFR Part 60. [s. 285.65(3), Wis. Stats.] (3) <u>Stack Parameters</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 18 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 2.12 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (4) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for Particulate Matter Emissions:</u> Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.1.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) The permittee shall record information on the maintenance required in condition I.C.1.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code] (6) The permittee shall record the start and end times of the diesel generator operation to demonstrate compliance with condition I.C.2.a.(5). [s. 285.65(3), Wis. Stats.]

15 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

<table>
<tr><td colspan="2">C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2
The following emission limits apply to each Diesel Generator.</td></tr>
<tr><td colspan="2">Pollutant: 3. Sulfur Dioxide</td></tr>
<tr><td colspan="2">a. Limitations: (1) The emissions may not exceed 0.05 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight . (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) The permittee shall determine the hourly emissions using fuel consumption records, fuel sulfur content and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire fuel oil having a sulfur content of 0.003% by weight . This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]</td><td>(1) <u>Reference Test Method for Sulfur Dioxide Emissions:</u> Whenever compliance emission testing is required, US EPA Method 6, 6A or 6C shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(2), Wis. Adm. Code]

(2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.3.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process’s fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.C.3.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]</td></tr>
</table>

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2 The following emission limits apply to each Diesel Generator.	
Pollutant: 3. Sulfur Dioxide (continued)	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(4) A representative sample shall be taken from each fuel lot of fuel oil received. The sample shall be analyzed by the permittee for the sulfur content by weight using procedures outline in s. NR 439.08(2), Wis. Adm. Code and the analysis shall be retained by the permittee for a period of at least five years. [s. 285.65(3), Wis. Stats.] (5) The Department will accept, in lieu of an analysis on each fuel lot under (4) above, an analysis of a representative sample of the fuel lot of distillate fuel oil from which the fuel lot was taken. [s. 285.65(3), Wis. Stats.] (6) The permittee shall retain copies of its distillate fuel oil supplier's fuel sulfur and heat content analyses at the facility for each fuel lot of distillate fuel oil received pursuant to 40 CFR 60.334 for a period of five years. [s. NR 439.04(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (7) The permittee shall further obtain certification from the fuel supplier that the applicable methods in s. NR 439.08(2), Wis. Adm. Code, were followed, if applicable, by the supplier in the preparation of said sulfur and heat content analyses. The fuel lot's quantity of fuel oil shall be included with the copies of these analyses. [s. 285.65(3), Wis. Stats.]	(5) The permittee shall keep records required under condition I.C.3.b.(4) – (7). [s. NR 439.04(1)(d), Wis. Adm. Code]

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2 **The following emission limits apply to each Diesel Generator.**	
Pollutant: 4. Oxides of Nitrogen (NOx)	
a. Limitations: (1) The emissions may not exceed 6.9 g/bhp-hr and 33.4 pounds per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. NR 428.04(2)(h), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using operating parameters and certified emission test data as required by 40 CFR Part 60. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for Nitrogen Oxide Emissions:</u> Whenever compliance emission testing is required, test procedures in 40 CFR 60, US EPA Method 7 or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(6), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.4.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.C.4.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code] (5) The permittee shall comply with the general and specific monitoring requirements under s. NR 428.04(3)(a) and (b), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (6) The permittee shall comply with all the recordkeeping and reporting requirements under s. NR 428.04(4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(4), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (7) The permittee shall comply with all the requirements for monitoring, installation, certification, data accounting, compliance dates and reporting data prior to initial certification as required under s. NR 428.07(1)(b), Wis. Adm. Code, s. NR 428.07(2)(b)2, Wis. Adm. Code, s, NR 428.07(3), Wis. Adm. Code. [s. 285.65(3), Wis. Stats.] (8) The permittee shall submit quarterly reports per s. NR 428.09(2), (3) and (4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(9), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

Note 1: The diesel generator is subject to s. NR 428.04(2)(h), Wis. Adm. Code and is 6.9 grams per brake horsepower when firing natural gas and firing fuel oil for NOx. The BACT limit for NOx is more restrictive then the NOx limit under s. NR 428,04, Wis. Adm. Code, thus the diesel generator is expected to meet the NOx limits under s. NR 428.04, Wis. Adm. Code.

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2 **The following emission limits apply to each Diesel Generator.**	
Pollutant: 5. Carbon Monoxide	
a. Limitations: (1) The emissions may not exceed 41.19 pounds per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using operating parameters and certified emission test data as required by 40 CFR Part 60. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for Carbon Monoxide Emissions:</u> Whenever compliance emission testing is required, test procedures in 40 CFR Part 60, US EPA Method 10, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(4), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.5.a.(2). [s. 285.65(10), Wis. Stats., 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.C.5.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, -Emergency Diesel Generator 2 **The following emission limits apply to each Diesel Generator.**	
Pollutant: 6. Volatile Organic Compounds (VOC)	
b. Limitations: (1) The emissions may not exceed 4.8 pounds per hour. (LAER); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (LAER); (4) The use of good combustion practices. (LAER) [s. NR 408.04, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using operating parameters and certified emission test data as required by 40 CFR Part 60. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet LAER emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for VOC Emissions:</u> Whenever compliance emission testing is required, test procedures in 40 CFR Part 60, US EPA Method 25 or 18, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(3), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.6.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.C.6.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2 The following emission limits apply to each Diesel Generator.	
Pollutant: 7. Lead Emissions	
a. Limitations: (1) The emissions may not exceed 0.000114 pound per hour . (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight.. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for Lead Emissions:</u> Whenever compliance emission testing is required, US EPA Method 12 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(5), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.7.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.C.7.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

<table>
<tr><td colspan="2">C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2
The following emission limits apply to each Diesel Generator.</td></tr>
<tr><td colspan="2">Pollutant: 8. Mercury Emissions</td></tr>
<tr><td colspan="2">a. Limitations: (1) The emissions may not exceed 0.00000682 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]</td><td>(1) <u>Reference Test Method for Mercury Emissions:</u> Whenever compliance emission testing is required, US EPA Method 29 or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code]

(2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.8.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.C.8.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]</td></tr>
</table>

C. S62, B62, – Emergency Diesel Generator 1; S63, B63, - Emergency Diesel Generator 2 **The following emission limits apply to each Diesel Generator.**	
Pollutant: 9. Emissions of Fluorides	
a. Limitations: (1) The emissions may not exceed 0.00088 pound per million Btu Heat Input . (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Emissions of Fluorides: Whenever compliance emission testing is required, US EPA Method 13B shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.9.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.C.9.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

Pollutant: 10. Visible Emissions	
a. Limitations: 20% opacity or number 1 on the Ringlemann chart. [s. NR 431.05, Wis. Adm. Code]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2 The following emission limits apply to each Diesel Generator.	
Pollutant: 11. Hazardous air pollutants (inorganic solid HAPs, inorganic acid HAPs, Organic HAPs) regulated under sec. 112 of the Clean Air Act.	
a. Limitations: (1) The permittee shall use fuel oil having a maximum sulfur content of 0.003% by weight and comply with the PM/PM10 limits to meet case by case MACT for inorganic solid HAPs; (2) The permittee shall use fuel oil having a maximum sulfur content of 0.003% by weight to comply with the case by case MACT limits for inorganic acid HAPs; (3) The permittee shall comply with and meet the VOC emission limits to comply with case by case MACT for organic HAPs and (4) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (5) The use of good combustion practices. (BACT) [s. 285.65 (13), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet MACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the engine generator; and (b) A list of items that will be checked and maintained and their frequency, to ensure that engine generator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for organic HAPs Emissions; inorganic solid HAPs, and inorganic acid HAPs: Whenever compliance emission testing is required method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.C.11.a.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.C.11.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

C. S62, P62, – Emergency Diesel Generator 1; S63, P63, - Emergency Diesel Generator 2 **The following emission limits apply to each Diesel Generator.**	
Pollutant: 12. Sulfuric Acid Mist	
a. Limitations: (1) The emissions may not exceed 0.005 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. [s. NR 405.08(2), Wis. Adm. Code; s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight . This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (2) The permittee shall determine the hourly emissions using fuel consumption records, and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Sulfur Acid Mist Emissions: Whenever compliance emission testing is required, US EPA Method 8 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall keep an operating log, which records the monthly hours of operation, to demonstrate compliance with condition I.C.12.a.(2). [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (3) The permittee shall retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. 285.65(3), Wis. Stats.] (4) The permittee shall keep records required under condition I.C.3.b.(4) – (7) to demonstrate compliance with the sulfur content in the fuel. [s. NR 439.04(1)(d), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump The following emission limits apply to each fire pump.	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: (1) The emissions may not exceed 0.21 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive month period.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight . (BACT); (4) The use of good combustion practices. (BACT); (5) The emissions unit may be operated only during the hours from 9:00 am to 1:00 PM. This condition is established to protect the ambient air quality standards. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.16 [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall determine the hourly emissions using fuel consumption and vendor provided emission factors. [s. 285.65(3), Wis. Stats.] (3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The height of stack S64 shall be at least 32 feet above ground level and the height of the stack S175 shall be at least 32 feet and the height of stack S176 shall be at least 12.0 feet. [s. 285.65(3), Wis. Stats, s. NR 406.10, Wis. Adm. Code] (b) The inside diameter at the outlet of the stack S64 may not exceed 0.7 feet and the inside diameter at the outlet of the stack S175 may not exceed 0.7 feet and the inside diameter at the outlet of the stack S176 may not exceed 0.7 feet. [s. 285.65(3), Wis. Stats, s. NR 406.10, Wis. Adm. Code] (4) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight . This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices : (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump; and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR 60 and US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.1.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) The permittee shall record information on the maintenance required in condition I.D.1.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code] (6) The permittee shall record the start and end times of the diesel generator operation to demonstrate compliance with condition I.D.1.a.(5). [s. 285.65(3), Wis. Stats.]

16 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump The following emission limits apply to each fire pump.	
Pollutant: 2. Particulate Matter Emissions less than 10 microns (PM_{10})	
a. Limitations: (1) The emissions may not exceed 0.21 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT); (5) The emissions unit may be operated only during the hours from 9:00 am to 1:00 pm. This condition is established to protect the ambient air quality standards. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.17 [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall determine the hourly emissions using operating parameters and certified test data as required by 40 CFR Part 60. [s. 285.65(3), Wis. Stats.] (3) <u>Stack Parameters</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The height of stack S64 shall be at least 32 feet above ground level and the height of the stack S175 shall be at least 32 feet and the height of stack S176 shall be at least 12.0 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The inside diameter at the outlet of the stack S64 may not exceed 0.7 feet and the inside diameter at the outlet of the stack S175 may not exceed 0.7 feet and the inside diameter at the outlet of the stack S176 may not exceed 0.7 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (4) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump; and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for Particulate Matter Emissions:</u> Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.2.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) The permittee shall record information on the maintenance required in condition I.D.2.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code] (6) The permittee shall record the start and end times of the diesel generator operation to demonstrate compliance with condition I.D.2.a.(5). [s. 285.65(3), Wis. Stats.]

17 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump The following emission limits apply to each fire pump.	
Pollutant: 3. Sulfur Dioxide	
a. Limitations: (1) The emissions may not exceed 0. 01 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records, fuel sulfur content and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump; and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for Sulfur Dioxide Emissions:</u> Whenever compliance emission testing is required, US EPA Method 6, 6A or 6C shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(2), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.3.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.D.3.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump The following emission limits apply to each fire pump. [CONTINUED]	
Pollutant: 3. Sulfur Dioxide (continued)	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(4) A representative sample shall be taken from each fuel lot of fuel oil received. The sample shall be analyzed by the permittee for the sulfur content by weight using procedures outline in s. NR 439.08(2), Wis. Adm. Code and the analysis shall be retained by the permittee for a period of at least five years. [s. 285.65(3), Wis. Stats.] (5) The Department will accept, in lieu of an analysis on each fuel lot under (4) above, an analysis of a representative sample of the fuel lot of distillate fuel oil from which the fuel lot was taken. [s. 285.65(3), Wis. Stats.] (6) The permittee shall retain copies of its distillate fuel oil supplier's fuel sulfur and heat content analyses at the facility for each fuel lot of distillate fuel oil received pursuant to 40 CFR 60.334 for a period of five years. [s. NR 439.04(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (7) The permittee shall further obtain certification from the fuel supplier that the applicable methods in s. NR 439.08(2), Wis. Adm. Code, were followed, if applicable, by the supplier in the preparation of said sulfur and heat content analyses. The fuel lot's quantity of fuel oil shall be included with the copies of these analyses. [s. 285.65(3), Wis. Stats.]	(5) The permittee shall keep records required under condition I.D.3.b.(4) – (7). [s. NR 439.04(1)(d), Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump The following emission limits apply to each fire pump.	
Pollutant: 4. Oxides of Nitrogen	
a. Limitations: (1) The emissions may not exceed 14.0 pounds per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and vendor provided emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Nitrogen Oxide Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR 60, US EPA Method 7 or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(6), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.4.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.D.4.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump The following emission limits apply to each fire pump.	
Pollutant: 5. Carbon Monoxide	
a. Limitations: (1) The emissions may not exceed 3.36 pounds per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and vendor provided emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Carbon Monoxide Emissions: Whenever compliance emission testing is required, US EPA Method 10, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(4), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.5.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.D.5.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump
The following emission limits apply to each fire pump.

Pollutant: 6. Volatile Organic Compounds (VOC)

a. Limitations: (1) The emissions may not exceed 0.31 pounds per hour. (LAER); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (LAER); (4) The use of good combustion practices. (LAER) [s. NR 408.04, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]

b. Compliance Demonstration:	c. Test Methods, Recordkeeping, and Monitoring:
(1) The permittee shall determine the hourly emissions using fuel consumption records and vendor provided emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight . This condition is established to meet LAER emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump; and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for VOC Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR Part 60, Appendix A, US EPA Method 25 or 18, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.6.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.D.6.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump The following emission limits apply to each fire pump.	
Pollutant: 7. Lead Emissions	
a. Limitations: (1) The emissions may not exceed 0.0000274 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive month period.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight . (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump; and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for Lead Emissions:</u> Whenever compliance emission testing is required, US EPA Method 12 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(5), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.7.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.D.7.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump The following emission limits apply to each fire pump.	
Pollutant: 8. Mercury Emissions	
a. Limitations: (1) The emissions may not exceed 0.00000164 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump; and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Mercury Emissions: Whenever compliance emission testing is required, US EPA Method 29 or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.8.a.(2). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.D.8.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump **The following emission limits apply to each fire pump.**	
Pollutant: 9. Emissions of Fluorides	
Limitations: (1) The emissions may not exceed 0.00000376 pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Emissions of Fluorides: Whenever compliance emission testing is required, US EPA Method 13B shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.9.a.(2). [s. 285.65(10), Wis. Stats., 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.D.9.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code

Pollutant: 10. Visible Emissions	
a. Limitations: 20% opacity or number 1 on the Ringlemann chart. [s. NR 431.05, Wis. Adm. Code]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump **The following emission limits apply to each fire pump.**	
Pollutant: 11. Hazardous air pollutants (inorganic solid HAPs, inorganic acid HAPs, Organic HAPs) regulated under sec. 112 of the Clean Air Act.	
a. Limitations: (1) The permittee shall use fuel oil having a maximum sulfur content of 0.003% sulfur by weight and comply with the PM/PM10 limits to meet case by case MACT for inorganic solid HAPs; (2) The permittee shall us fuel oil having a maximum sulfur content of 0.003% by weight to comply with the case by case MACT limits for inorganic acid HAPs; (3) The permittee shall comply with and meet the VOC emission limits to comply with case by case MACT for organic HAPs and (4) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (5) The use of good combustion practices. (BACT) [s. NR 445.04(3)(a), Wis. Adm. Code]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet MACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fire pump; and (b) A list of items that will be checked and maintained and their frequency, to ensure that fire pump is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for organic HAPs Emissions; inorganic solid HAPs, and inorganic acid HAPs:</u> Whenever compliance emission testing is required a method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record the monthly hours of operation, to demonstrate compliance with condition I.D.11.a.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.D.11.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

D. S64, P64 – Emergency Diesel Driven Fire Pump; S175, P175 – Emergency Boiler Building Driven Fire Booster Pump; S176, P176 – Emergency Crusher Tower Diesel Driven Fire Booster Pump The following emission limits apply to each fire pump.	
Pollutant: 12. Sulfuric Acid Mist	
a. Limitations: (1) The emissions may not exceed 0.001pound per hour. (BACT); (2) The hours of operation may not exceed 500 hours in any 12 consecutive months.; (3) The use of fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (4) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall fire fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (2) The permittee shall determine the hourly emissions using fuel consumption records, and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Sulfur Acid Mist Emissions: Whenever compliance emission testing is required, US EPA Method 8 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall keep an operating log, which records the monthly hours of operation, to demonstrate compliance with condition I.D.12.a.(2). [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (3) The permittee shall retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. 285.65(3), Wis. Stats.] (4) The permittee shall keep records required under condition I.D.3.b.(4) – (7) to demonstrate compliance with the sulfur content in the fuel. [s. NR 439.04(1)(d), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

E. S23, P23 – Crusher House Dust Collector No. 1; S24, P24 – Crusher House Dust Collector No. 2 **The following emission limits apply to each crusher house duct collector.**	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 1.307 pounds per hour. (BACT) [s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests for one of the crusher house dust collector 1 or 2 shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.18 [s. NR 439.07, Wis. Adm. Code] (2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 160 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 3.73 Feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.E.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

18 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

E. S23, P23 – Crusher House Dust Collector No. 1; S24, P24 – Crusher House Dust Collector No. 2 **The following emission limits apply to each crusher house duct collector.**	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity. [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 440.42(3)(c), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.E.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

Note 1: The coal handling/storage operations are subject to s. NR 440.42(3)(c), Wis. Adm. Code (New Source Performance Standards, NSPS requirements) for visible emissions. For these operation, s. NR 440.42(3)(c), Wis. Adm. Code prohibits visible emissions of 20 percent opacity or greater for any coal processes and conveying equipment, coal storage system, or coal transfer and loading system. The BACT limit for opacity is more restrictive then NSPS limits for opacity thus the crusher house operation is expected to be in compliance with the NSPS emission limits for opacity.

F. S27, P27- Fly Ash Silo Filter Vent 1; S65, P65 – Fly Ash Silo Filter Vent 2 **The following emission limits apply to each of the fly ash silo filter vent.**	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.02 grains per dry standard cubic foot of exhaust gas and 0.394 pound per hour. (BACT) [s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine hourly emissions using operating parameters and OEM emission factors. [s. 285.65(3), Wis. Stats.] (2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 120 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 3.4 Feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a bin vent filter system to meet BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (4) The bin vent filter system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The permittee shall develop and follow a Malfunction Prevention and Abatement Plan for the bin vent filter system. The plan shall identify the specific measures that will be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific measures could include: filter inspection schedule, filter replacement criteria, etc. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (6) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (7) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters and bin vent filter. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the bin vent filter system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

F. S27, P27- Fly Ash Silo Filter Vent 1; S65, P65 – Fly Ash Silo Filter Vent 2 **The following emission limits apply to each of the fly ash silo filter vent.**	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity. [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The bin vent filter system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The compliance method in I.F.1.b. shall be used to demonstrate compliance with the visible emission limits. [s. NR 407.09(4)(a)1., Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the bin vent filter system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

G. S28, P28 - Existing Junction House 7/8 Dust Collector	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.01 grains per dry standard cubic foot of exhaust gas and 2.331 pounds per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[19] [s. NR 439.07, Wis. Adm. Code] (2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 175 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 3.1 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.G.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

19 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

G. S28, P28 - Existing Junction House 7/8 Dust Collector	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity. [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.G.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

<table>
<tr><th colspan="2">H. S47, P47 – Limestone Prep Building Dust Collector</th></tr>
<tr><td colspan="2">Pollutant: 1. Particulate Matter Emissions</td></tr>
<tr><td colspan="2">a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 0.480 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. NR 440.688(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] See Note 1</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[20] [s. NR 440.688(6)(b), Wis. Adm. Code, s. NR 439.07, Wis. Adm. Code]

(2) <u>Stack Parameters</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 60 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 2.3 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.H.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]

(8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]</td><td>(1) <u>Reference Test Method for Particulate Matter Emissions:</u> Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 440.688(6)(b), Wis. Adm. Code, s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]</td></tr>
</table>

Note 1: The limestone prep operation is subject to New Source Performance Standards (NSPS) for particulate matter under s. NR 440.688(3), Wis. Adm. Code and the limit is 0.022 gr/acf. The BACT limit for particulate matter is more restrictive than NSPS limit for particulate matter thus the limestone prep operation is expected to meet the NSPS emission limit for particulate matter.

[20] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

H. S47, P47 – Limestone Prep Building Dust Collector	
Pollutant: 2. Visible Emissions	
a. Limitations: 7% opacity. [s. NR431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. NR 440.688(3)(a), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.H.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The permittee shall determine compliance with the visible emission limits using EPA Approved Method 9. [s. NR 440.688(6)(b)2., Wis. Adm. Code. [s. 285.65(3), Wis. Stats.] (4) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (5) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code] (5) The permittee shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the visible emission limits in I.H.2.a. Including reports of opacity observations made using Method 9. [s. 285.65(3), Wis. Stats.]

Note 1: The limestone prep operation is subject to New Source Performance Standards (NSPS) to visible emissions limit under s. NR 440.688(3), Wis. Adm. Code and the limit is 7% opacity.

<table>
<tr><th colspan="2">I S48, P48 - XFr Tower No. 3 And Tripper Room Unit 1 Dust Collector</th></tr>
<tr><td colspan="2">Pollutant: 1. Particulate Matter Emissions</td></tr>
<tr><td colspan="2">a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 1.759 pounds per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]</td></tr>
<tr><th>b. Compliance Demonstration:</th><th>c. Test Methods, Recordkeeping, and Monitoring:</th></tr>
<tr><td>(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[21] [s. NR 439.07, Wis. Adm. Code]

(2) <u>Stack Parameters</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 280 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 4.33 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet BACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.I.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]

(8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]</td><td>(1) <u>Reference Test Method for Particulate Matter Emissions:</u> Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]</td></tr>
</table>

21 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

I S48, P48 - XFr Tower No. 3 And Tripper Room Unit 1 Dust Collector	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.I.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

J. S49, P49 - Tripper Room Dust Collector Unit 2	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 1.182 pounds per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[22] [s. NR 439.07, Wis. Adm. Code] (2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 240 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 3.6 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.J.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

[22] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

J. S49, P49 – Tripper Room Dust Collector Unit 2	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.J.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

<table>
<tr><th colspan="2">K. S58, P58 - XFr Tower House #5 Dust Collector</th></tr>
<tr><td colspan="2">Pollutant: 1. Particulate Matter Emissions</td></tr>
<tr><td colspan="2">a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 0.567 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.23 [s. NR 439.07, Wis. Adm. Code]

(2) <u>Stack Parameters</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 196 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 2.5 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.K.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]

(8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]</td><td>(1) <u>Reference Test Method for Particulate Matter Emissions:</u> Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]</td></tr>
</table>

23 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

K. S58, P58 – XFr Tower House #5 Dust Collector	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.K.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

L. S59A, P59A - IGCC Coal Silos Dust Collector a; S59B, P59B – IGCC Coal Silos Dust Collector b The following emission limits apply to each IGCC coal silos dust collector.	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 1.371 pounds per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests on any one IGCC coal silos dust collector or b shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.24 [s. NR 439.07, Wis. Adm. Code] (2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 130 feet above ground level. [s. 285.65(3), Wis. Stats, s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 3.8 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determined during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.L.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

24 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

L. S59A, P59A - IGCC Coal Silos Dust Collector a; S59B, P59B – IGCC Coal Silos Dust Collector b **The following emission limits apply to each IGCC coal silos dust collector.**	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. NR 440.42(3)(c), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.L.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

Note 1: The coal handling/storage operations are subject to s. NR 440.42(3)(c), Wis. Adm. Code (New Source Performance Standards, NSPS requirements) visible emissions. For these operation, s. NR 440.42(3)(c), Wis. Adm. Code prohibits visible emissions of 20 percent opacity or greater for any coal processes and conveying equipment, coal storage system, or coal transfer and loading system. The BACT limit for opacity is more restrictive then NSPS limits for opacity thus the coal handling/storage operations is expected to be in compliance with the NSPS visible emission limits.

M. S66, P66 – XFr Tower No. 4 Dust Collector	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 0.944 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[25] [s. NR 439.07, Wis. Adm. Code] (2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 25 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 3.2 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.M.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

25 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

M. S66, P66 - Transfer Tower No. 4 Dust Collector	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.M.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

N. S76, P76 - Coal Car Dumper Dust Collector No. 1	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 5.531 pounds per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.26 [s. NR 439.07, Wis. Adm. Code] (2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 60 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 7.68 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10 and s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.B.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the process is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

26 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

N. S76, P76 - Coal Car Dumper Dust Collector No. 1	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s, NR 440.42(3)(c), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.N.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the process is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

<table>
<tr><td colspan="2">O. S93A – S93T, P93 – Active Coal Storage and handling Operations Building Ventilators a-t
The limits apply to each stack associated with the coal storage building ventilators.</td></tr>
<tr><td colspan="2">Pollutant: 1.   Particulate Matter Emissions</td></tr>
<tr><td colspan="2">a. Limitations: 0.024 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) The permittee shall utilize a building to control emissions from coal stackout, storage and reclaim operations, a stackout conveyor – with telescopic chute or travelling stacking conveyor with short drop, and coal reclaim system with short chute drop and loading table to minimize emissions and to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(2) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits.[s. NR 415.04(1)(b), Wis. Adm. Code]

(3) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.]

(4) The permittee shall ensure that the Trained Person designated:
(a) Has training to evaluate compliance with Wisconsin air quality regulations, or
(b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or
(c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit.
[s. 285.65(3), Wis. Stats.]

(5) The permittee shall determine the hourly emissions using the hourly throughput and AP-42 emission factors. [s. 285.65(3), Wis. Stats.]</td><td>(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 5 and Method 202 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

(2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code]

(3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code]

(4) The Trained Person designated by condition I.O.1.b.(3) shall sign and date the records required in I.O.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall ensure that records of the Trained Person designated by condition I.O.1.b.(4)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]</td></tr>
</table>

O. S93A – S93T, P93 – Active Coal Storage and Handling Operations Building Ventilators a-t The limits apply to each stack associated with the coal storage building ventilators.	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity. (Best Available Control Technology, BACT) [s. NR 431.05, Wis. Adm. Code, s. NR 405.08(2), Wis. Adm. Code, s. NR 440.42(3)(c), Wis. Adm. Code, s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions.

P. S104, P104 – Gypsum Storage and Handling Operations Building Exhaust Fan No. 1; S105, P105 – Exhaust Fan No. 2; S106, P106 – Exhaust Fan No. 3 **The following emission limits apply to each gypsum building exhaust fan.**	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.377 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall utilize a building to control emissions from gypsum stackout, storage and reclaim operations, and a reversible shuttle conveyor to distribute gypsum along the pile crest with short drop to minimize emissions and to minimize emissions and to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (2) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits.[s. NR 415.04(1)(b), Wis. Adm. Code] (3) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (4) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.] (5) The permittee shall determine the hourly emissions using hourly throughput and AP-42 emission factors. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 5 and Method 202 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code] (3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code] (4) The Trained Person designated by condition I.P.1.b.(3) shall sign and date the records required in I.P.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.] (5) The permittee shall ensure that records of the Trained Person designated by condition I.P.1.b.(4)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

P. S104, P104 – Gypsum Storage and Handling Operations Building Exhaust Fan No. 1; S105, P105 – Exhaust Fan No. 2; S106, P106 – Building Exhaust Fan No. 3 **The following emission limits apply to each gypsum building exhaust fan.**	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity. (Best Available Control Technology, BACT) [s. NR 431.05, Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. NR 440.42(3)(c), Wis. Adm. Code, s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions.

Q. S109, P109- Fuel Ash Building Exhaust Fan	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.240 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall utilize a building to control emissions from fuel ash stackout, storage, and reclaim operations, stackout drop from telescopic chute and reclaim fuel ash into hopper via front end loader to minimize emissions and to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (2) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits.[s. NR 415.04(1)(b), Wis. Adm. Code] (3) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (4) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.] (5) The permittee shall determine the hourly emissions using throughput and AP-42 emission factors. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 5 and Method 202 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code] (3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code] (4) The Trained Person designated by condition I.Q.1.b.(3) shall sign and date the records required in I.Q.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.] (5) The permittee shall ensure that records of the Trained Person designated by condition I.Q.1.b.(4) training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

Q. S109, P109 – Ash Reburn Building Exhaust Fan	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity. (Best Available Control Technology, BACT) [s. NR 431.05, Wis. Adm. Code, s. NR 405.08(2), Wis. Adm. Code, s. NR 440.42(3)(c), Wis. Adm. Code, s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions.

R. S114, P31- OCPP Fly Ash Storage Building Dust Collector	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 0.350 pound per hour. (BACT) [s. NR 415.06(2), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 90 after the start of operation of the process to show compliance with the emission limitation.27 [s. NR 439.07, Wis. Adm. Code] (2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 40 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 0.9 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse system. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation to meet the BACT limits. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determined during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.R.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) (a)The fly ash storage facility shall receive fly ash either by bulk tanker truck or fully enclosed pneumatically conveyors. (b) The bulk truck loading be done in a fully enclosed structure. [s. 285.65(3), Wis. Stats.] This condition is established to ensure no fugitive dust is generated by the fly ash storage facility's operation. Also based on this condition no emissions are expected from the equipment used to transfer material to and from the fly ash storage facility. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the process is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

27 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

R. S114, P31- Fly Ash Storage Building Exhaust Fan Dust Collector	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity. [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.R.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the process is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

S. S149, P149 - Gypsum XFr Tower No. 1 Dust Collector.	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.005 grains per dry standard cubic foot of exhaust gas and 0.504 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.28 [s. NR 439.07, Wis. Adm. Code] (2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 35 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 2.1 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse filter system to meet the BACT limit. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.S.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

28 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

S. S149, P149- Gypsum XFr Tower No. 1 Dust Collector.	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The compliance method in I.S.1.b. shall be used to demonstrate compliance with the visible emission limits. [s. NR 407.09(4)(a)1., Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

T. S150, P150 – Gypsum XFr Tower No. 2 Dust Collector.

Pollutant: 1. Particulate Matter Emissions

a. Limitations: 0.005 grains per dry standard cubic foot of exhaust gas and 0.450 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

b. Compliance Demonstration:

(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[29] [s. NR 439.07, Wis. Adm. Code]

(2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 35 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 1.96 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code]

(4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code]

(5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.]

(6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.T.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code]

(7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.]

(8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]

c. Test Methods, Recordkeeping, and Monitoring:

(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code]

(4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

(5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

[29] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

T. S150, P150- Gypsum XFr Tower No. 2 Dust Collector.	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The compliance method in I.T.1.b. shall be used to demonstrate compliance with the visible emission limits. [s. NR 407.09(4)(a)1., Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

U. S169a, P169a - Fly Ash Silo No 1 Vacuum Exhauster a; S169b, P169b - Fly Ash Silo No 1 Vacuum Exhauster b; S170a, P170a - Fly Ash Silo No 2 Vacuum Exhauster a; S170 b, P170b - Fly Ash Silo No 2 Vacuum Exhauster b The following emission limits apply to each fly ash silo vacuum exhauster.	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.02 grains per dry standard cubic foot of exhaust gas and 0.369 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code; s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using operating parameters and OEM emission factors. [s. 285.65(3), Wis. Stats.] (2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 30 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 1.0 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a filter separator system to meet BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (4) The filter separator system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The permittee shall develop and follow a Malfunction, Prevention and Abatement Plan for the filter separator system. The plan shall identify the specific measures that will be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific measures could include: filter inspection schedule, filter replacement criteria, etc. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack and file separator system parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the filter separator system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

U. S169a, P169a - Fly Ash Silo No 1 Vacuum Exhauster a; S169b, P169b - Fly Ash Silo No 1 Vacuum Exhauster b; S170a, P170a - Fly Ash Silo No 2 Vacuum Exhauster a; S170 b, P170b - Fly Ash Silo No 2 Vacuum Exhauster b **The following emission limits apply to each fly ash silo vacuum exhauster.**	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity. [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The filter separator system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The compliance method in I.U, 1.b. shall be used to demonstrate compliance with the visible emission limits. [s. NR 407.09(4)(a)1., Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the filter separator system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code]

V. S171, P171 - Gypsum Hopper Dust Collector	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 1.80 pounds per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code; s. 285.65(3), Wis. Stats]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.30 [s. NR 439.07, Wis. Adm. Code] (2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 75 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 4.4 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) Particulate matter emissions shall be controlled using a fabric filter baghouse system to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.V.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

30 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

V. S171, P171- Gypsum Hopper Dust Collector	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The compliance method in I.V, 1.b. shall be used to demonstrate compliance with the visible emission limits. [s. NR 407.09(4)(a)1., Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

W. S172, P172 – Limestone Loading Table Insertable Bin Vent Filter	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 0.171 pound per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. NR 440.688(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine hourly emissions using operating parameters and OEM emission factors. [s. 285.65(3), Wis. Stats.] (2) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 25 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (Ib) The stack inside diameter at the outlet may not exceed 1.4 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) (a) Particulate matter emissions shall be controlled using a bin vent filter system to meet the BACT limits. (b) The limestone loading table will be connected to the limestone unloader and will travel along the dock conveyor. [s. NR 405.08(2), Wis. Adm. Code] (4) The bin vent filter system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the bin vent filter system shall be determined during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the bin vent filter system shall be maintained within the range identified by condition I.W.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation. [s. NR 440.688(6)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 440.688(6)9b), Wis. Adm. Code, s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack and bin vent filter parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the bin vent filter system every eight hours whenever the process is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the bin vent filter system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the bin vent filter system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

Note 1: The limestone loading table operation is subject to New Source Performance Standards (NSPS) for particulate matter under s. NR 440.688(3), Wis. Adm. Code and the limit is 0.022 gr/acf. The BACT limit for particulate matter is more restrictive than particulate matter emission limit under NSPS, thus the limestone loading table operation is expected to meet the particulate matter emission limit under NSPS.

W. S172, P172 – Limestone Loading Table Insertable Bin Vent Filter	
Pollutant: 2. Visible Emissions	
a. Limitations: 7% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. NR 440.688(3)(a), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The bin vent filter system shall be in line and shall be operated at all times when the process is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the bin vent filter system shall be maintained within the range identified by condition I.W.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The permittee shall determine compliance with the visible emission limits using EPA approved Method 9. [s. NR 440.688(6)(b)2., Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the bin vent filter system every eight hours whenever the process is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the bin vent filter system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the bin vent filter system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code] (5) The permittee shall submit written reports of the results of all performance test conducted to demonstrate compliance with the visible emission limits in I.W.2.a. including reports of opacity observations made using EPA Method 9. [s. 285.65(3), Wis. Stats.]

Note 1: The proposed operation is subject to New Source Performance Standards (NSPS) under s. NR 440.688(3), Wis. Adm. Code and the limit is 7% opacity.

X. S178, P178 - Coal Transfer Tower No. 2a Dust Collector and S179, P179 – Coal Transfer Tower No. 2b **The following emission limits apply to each Process**	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: 0.004 grains per dry standard cubic foot of exhaust gas and 2.197 pounds per hour. (BACT) [s. NR 415.06(2)(c), Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[31] [s. NR 439.07, Wis. Adm. Code] (2) <u>Stack Parameters</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height for S178 shall be at least 80 feet above ground level and the stack height for S179 shall be at least 60.0 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet for S178 may not exceed 3.7 feet and the stack inside diameter at the outlet for S179 may not exceed 3.2 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (3) (a) The transfer tower #1 will be completely enclosed structure. (b) Particulate matter emissions shall be controlled using a fabric filter baghouse system. [s. NR 405.08(2), Wis. Adm. Code] (4) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (5) The operating pressure drop range across the fabric filter baghouse system shall be determine during the initial testing period. [s. 285.65(3), Wis. Stats.] (6) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.X.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (7) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (8) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Particulate Matter Emissions:</u> Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (4) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

31 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

XI. X. S178, P178 - Coal Transfer Tower No. 2a Dust Collector and S179, P179 – Coal Transfer Tower No. 2b **The following emission limits apply to each Process**	
Pollutant: 2. Visible Emissions	
a. Limitations: 10% opacity [s. NR 431.05, Wis. Adm. Code, s. NR 405.09, Wis. Adm. Code, s. NR 440.42(3)(c), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fabric filter baghouse system shall be in line and shall be operated at all times that the dust collection system is in operation. [s. NR 406.10, Wis. Adm. Code, s. NR 407.09(4)(a)1., Wis. Adm. Code] (2) The pressure drop across the fabric filter baghouse system shall be maintained within the range identified by condition I.X.1.b.(5). [s. NR 407.09(4)(a)1., Wis. Adm. Code] (3) The process shall be monitored in accordance with a Fugitive Dust Control Plan. The Department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. 285.65(3), Wis. Stats.] (4) Whenever fugitive dust emissions are observed form the process, the permittee shall take corrective actions to prevent fugitive dust from becoming airborne. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall record the pressure drop across the fabric filter baghouse system every eight hours whenever the dust collection system is in operation. [s. NR 439.055(2)(b)1., Wis. Adm. Code] (3) The permittee shall keep records of all inspections, checks and any maintenance or repairs performed on the fabric filter baghouse system, containing the date of the action, initials of inspector, and the results. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) Instrumentation to monitor the pressure drop across the fabric filter baghouse system shall be installed and operated properly. [s. NR 439.055(1)(a), Wis. Adm. Code]

Note 1: The coal handling/storage operations are subject to s. NR 440.42(3)(c), Wis. Adm. Code (New Source Performance Standards, NSPS requirements) for visible emissions. For these operation, s. NR 440.42(3)(c), Wis. Adm. Code prohibits visible emissions of 20 percent opacity or greater for any coal processes and conveying equipment, coal storage system, or coal transfer and loading system. The limit for opacity established for this process is more restrictive then NSPS limits for opacity, thus the coal handling/storage operation is expected to be in compliance with the opacity emission limits under NSPS.

Y. F29, F29B, F31, S29, S29B, S31 – Inactive Coal Pile A Reclaim & Wind Erosion; F32, S32, - Inactive Coal Pile B Reclaim & Wind Erosion **The following emission limits to each coal pile.**	
Pollutant: 1. Fugitive Dust (PM/PM10)	
a. Limitations: No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) (a) Coal loaded out to the inactive coal storage pile shall be compacted in accordance with standard coal pile maintenance procedures. (b) Once compacted, the bulk of the pile will be left undisturbed (inactive). [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (2) (a) A surfactant (wet suppression spray and/or surface stabilizing agent) or cover material(s), shall be applied to the pile. The surfactant (wet suppression spray and/or surface stabilizing agent) shall be applied to the active area of the pile at the beginning and end of each at stack out and reclaim activity. (b) In addition to the beginning and ending applications, surfactant (wet suppression spray and/or surface stabilizing agent) will also be applied to the active area during reclaim activities whenever any visible emissions are seen beyond the coal pile boundary or whenever, in the option of the rained person, additional surfactant (wet suppression spray and/or surface stabilizing agent) is needed. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) (a)The permittee shall conduct weekly inspections of the inactive coal storage pile. (b) Additional surfactant will be applied whenever any visible emissions are seen beyond the coal pile boundary or whenever, in the opinion of the trained person, additional surfactant is needed. (c) In addition to weekly inspections, daily inspections of the active coal pile area, to determine the continued effectiveness of the surfactant, will be conducted by a trained person whenever coal is reclaimed from the pile. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code] (3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code] (4) The Trained Person designated by condition I.Y.1.b.(5) shall sign and date the records required in I.Y.1.c.(4) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.] (5) The permittee shall ensure that records of the Trained Person designated by condition I.Y.1.b.(6)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the prosperity fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

Y. F29, F29B, F31, S29, S29B, S31 – Inactive Coal Pile A Reclaim & Wind Erosion; F32, S32, - Inactive Coal Pile B Reclaim & Wind Erosion **The following emission limits to each coal pile.**	
Pollutant: 1. Fugitive Dust (PM/PM10)	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(4) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code] (5) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (6) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.]	

Z. F33, S33, F33B, S33B – Limestone Storage Pile And Reclaim Activity & Wind Erosion	
Pollutant: 1. Fugitive Dust (PM/PM10)	
a. Limitations: No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
1) (a) The limestone pile shall be wetted by means of a wet suppression system whenever visible emissions are seen beyond the limestone pile boundary or whenever in the opinion of the trained person, additional wet suppression is necessary. (b) Weekly inspections of the limestone storage pile will be conducted to insure the pile contains the proper moisture content to prevent fugitive dust emissions. (c) Daily inspections to determine the continued effectiveness of fugitive dust control measures shall be conducted whenever limestone is reclaimed to the limestone preparation building. (d) Limestone shall be transferred from the pile to the limestone preparation building in a covered conveyor. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (2) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits.[s. NR 415.04(1)(b), Wis. Adm. Code] (3) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (4) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code] (3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code] (4) The Trained Person designated by condition I..Z.1.b.(3) shall sign and date the records required in I.Z.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.] (5) The permittee shall ensure that records of the Trained Person designated by condition I.Z.1.b.(4)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

F34, S34, – Inactive Coal Piles – Stackout Drop Point for Pile AA	
Pollutant: 1. Fugitive Dust (PM/PM10)	
a. Limitations: No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Fixed portions of coal load-out to outdoor storage system shall be conducted within a covered conveyor to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (2) Dust created during coal load-out shall be suppressed using a liquid spray to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) Coal shall be transferred from the conveyor to the storage pile using a telescoping spout to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (4) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code] (5) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (6) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) (a)The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records including the use of wet suppression system. (b) The records shall consist of the date, time, observations, and any actions taken including the start and end times the wet suppression system is used. [s. NR 415.04(1)(b), Wis. Adm. Code] (3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code] (4) The Trained Person designated by condition I.AA.1.b.(5) shall sign and date the records required in I.AA.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.] (5) The permittee shall ensure that records of the Trained Person designated by condition I.AA.1.b.(6)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

BB. F37, S37 – Limestone Barge Unloading; F38, S38 - Limestone StackOut	
Pollutant: 1. Fugitive Dust (PM/PM10)	
a. Limitations: No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. [s. NR 405.09, Wis. Adm. Code, s. NR 440.688(3), Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) (a) Limestone shall be unloaded from the barge using either a screw auger (or rotary screw) or an enclosed hydraulic clamshell to meet the BACT limits. (b) Limestone load-out to outdoor storage shall be conducted within a covered conveyor equipped with a telescopic chute. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (2) Dust shall be suppressed using a liquid spray to meet BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code] (4) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (5) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code] (3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code] (4) The Trained Person designated by condition I.BB.1.b.(4) shall sign and date the records required inI.BB.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.] (5) The permittee shall ensure that records of the Trained Person designated by conditionI.BB.1.b.(5)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

<table>
<tr><td colspan="2">CC. F121,F121B, F123, S121, S121B, S123 – Gypsum Dock Side Storage Pile and Barge Loading Activity</td></tr>
<tr><td colspan="2">Pollutant: 1. Fugitive Dust (PM/PM10)</td></tr>
<tr><td colspan="2">a. Limitations: No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1). Gypsum loaded out to the dock side storage pile shall be covered with a tarp of sufficient size to cover the entire pile to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(2) A portion of the pile can be maintained in an “active” state to allow for appropriate barge loading activities to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(3) Active portions of the pile shall be wetted by means of a supplemental wet suppression system to a moisture content consistent with proper fugitive dust control whenever visible emissions are seen beyond the gypsum pile boundary or whenever, in the opinion of the trained person, addition wet suppression is necessary. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(4) Weekly inspections of the dock side gypsum storage pile will be conducted to insure that the pile is either covered or contains the proper moisture content to prevent fugitive dust emissions to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(5) Daily inspections of the active area to determine the continued effectiveness of fugitive dust control measures, shall be conducted by the trained person whenever gypsum is loaded out to the barge to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(6) The permittee shall transfer gypsum from the conveyor to the dock-side storage using a telescoping chute to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(7) The permittee shall use a covered conveyor equipped with a telescoping chute or enclosed clamshell when loading gypsum to the barge to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]</td><td>(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

(2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code]

(3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code]

(4) The Trained Person designated by condition I.CC.1.b.(9) shall sign and date the records required inI.CC.1.c.(8) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall ensure that records of the Trained Person designated by conditionI.CC.1.b.(10)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]</td></tr>
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CC. F121,F121B, F123, S121, S121B, S123 – Gypsum Dock Side Storage Pile and Barge Loading Activity	
Pollutant: 1. Fugitive Dust (PM/PM10) [CONTINUED]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(8) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits.[s. NR 415.04(1)(b), Wis. Adm. Code] (9) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (10) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.]	

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

DD. F122, F124, S122, S124 – Gypsum Drop Side Pile and Barge Loading Drop Points.	
Pollutant: 1. Fugitive Dust (PM/PM10)	
a. Limitations: No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Fixed portions of the gypsum load-out to outdoor storage system shall be conducted within a covered conveyor to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (2) Dust created during gypsum loadout shall be suppressed using a liquid spray to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (3) Gypsum shall be transferred from the conveyor to the storage pile using a telescoping spout to meet the BACT limits, [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (4) The permittee shall use a covered conveyor equipped with a telescopic chute or enclosed clamshell when loading Gypsum to the pile to meet the BACT limits. [s. 285.65(3), Wis. Stats.] (5) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code] (6) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (7) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code] (3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code] (4) The Trained Person designated by condition I.DD.1.b.(6) shall sign and date the records required inI.DD.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.] (5) The permittee shall ensure that records of the Trained Person designated by conditionI.DD.1.b.(6)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

EE. F125, S125 – Fuel Ash Reclaim – Maintenance and Front End Loader Excavate Drop to Trucks	
Pollutant: 1. Fugitive Dust (PM/PM10)	
a. Limitations: (1) No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. (2) The process may be operated only during the hours from 7:00 am to 7:00 PM. The permittee has elected this restriction to ensure the PM10 ambient air quality standards are not exceeded. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The fuel ash reclaim area shall be wetted by means of a wet suppression system whenever visible emissions are seen beyond the area's boundary or whenever, in the opinion of the trained person, additional wet suppression is necessary to meet the BACT limits. [s. 285.65(3), Wis. Stats.] (2) Weekly inspections of the fuel ash reclaim area will be conducted by a trained person to insure that the material to be reclaimed contains adequate moisture content to prevent fugitive dust emissions to meet BACT limits. [s. 285.65(3), Wis. Stats.] (3) In addition to weekly inspections, daily inspections, to determine the continued effectiveness of fugitive dust control measures, shall be conducted by the trained person, whenever fuel ash is reclaimed to meet BACT limits. [s. 285.65(3), Wis. Stats.] (4) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code] (5) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (6) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code] (3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code] (4) The Trained Person designated by condition I.EE.1.b.(5) shall sign and date the records required inI.EE.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.] (5) The permittee shall ensure that records of the Trained Person designated by conditionI.EE.1.b.(6)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.] (6) The permittee shall record the start and end times of the operation to demonstrate compliance with condition I.EE.1.a.(2). [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

FF. F44, S141 – S148 – Activities associated at the Caledonia Landfill.	
Pollutant: 1. Fugitive Dust (PM/PM10)	
a. Limitations: (1) No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. (2) The process may be operated only during the hours from 7:00 am to 7:00 PM. The permittee has elected this restriction to ensure the PM10 ambient air quality standards are not exceeded. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The landfill shall be wetted by means of a wet suppression system whenever visible emissions are seen beyond the landfill boundary or whenever, in the opinion of the trained person, additional wet suppression is necessary to meet the BACT limits. [s. 285.65(3), Wis. Stats.] (2) Weekly inspections of the materials storage landfill will be conducted by a trained person to insure that the material to be restored and reclaimed contains adequate moisture content to prevent fugitive dust emissions to meet BACT limits. [s. 285.65(3), Wis. Stats.] (3) In addition to weekly inspections, daily inspections, to determine the continued effectiveness of fugitive dust control measures, shall be conducted by the trained person, whenever fuel ash is reclaimed to meet BACT limits. [s. 285.65(3), Wis. Stats.] (4) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code] (5) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.] (6) The permittee shall ensure that the Trained Person designated: (a) Has training to evaluate compliance with Wisconsin air quality regulations, or (b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or (c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code] (3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code] (4) The Trained Person designated by condition I.FF.1.b.(5) shall sign and date the records required inI.FF.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.] (5) The permittee shall ensure that records of the Trained Person designated by conditionI.FF.1.b.(6)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.] (6) The permittee shall record the start and end times of the operation to demonstrate compliance with condition I.FF.1.a.(2). [s. 285.65(3), Wis. Stats.]

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

<table>
<tr><td colspan="2">GG. F174, F173, S173, S174 – Front End Loader reclaim of bottom ash – SCPC units to trucks.</td></tr>
<tr><td colspan="2">Pollutant: 1. Fugitive Dust (PM/PM10)</td></tr>
<tr><td colspan="2">a. Limitations: (1) No owner or operator may cause or allow emissions of density greater than 10% opacity from each fugitive dust source. (2) The process may be operated only during the hours from 7:00 am to 7:00 PM. The permittee has elected this restriction to ensure the PM10 ambient air quality standards are not exceeded. [s. NR 405.09, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) Dust created during bottom ash reclamation activities shall be suppressed using a water spray to meet BACT limits. [s. NR 405.08, Wis. Adm. Code, s. NR 406.10, Wis. Adm. Code, s. NR 415.04(1)(b), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(2) The permittee shall develop and follow a Fugitive Dust Control Plan for the subject site and operation. Any provisions of the plan that are applicable to the site are only applicable to the site while the plant is operated at the site. The Fugitive Dust Control Plan shall identify the specific measures to be taken, when needed and frequency needed to maintain emissions in compliance with emission limits. For example, specific dust control measures could include: watering all roads hourly and amount of water used, use of spray bars including amount and rate of water applied, or use of other approved dust suppressants. The department may request the permittee to review and amend the plan if necessary to maintain emissions in compliance with emission limits. [s. NR 415.04(1)(b), Wis. Adm. Code]

(3) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.]

(4) The permittee shall ensure that the Trained Person designated:
(a) Has training to evaluate compliance with Wisconsin air quality regulations, or
(b) Has obtained certification as a Method 9 opacity observer in the last 2 years , or
(c) Has attended appropriate training in other states or has other reasonable qualifications for being a Trained Person and the permittee has received written approval from the Department that such a person qualifies as a Trained Person for the purpose of this permit.
[s. 285.65(3), Wis. Stats.]</td><td>(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

(2) The permittee, for each day of operation of the plant, shall ensure that a person at the site keeps records of specific measures taken for that day in accordance with the Fugitive Dust Control Plan and signs and dates such records. [s. NR 415.04(1)(b), Wis. Adm. Code]

(3) These records shall be kept for a period of 5 years and be made available to Department personnel upon request. [s. NR 415.04(1)(b), Wis. Adm. Code]

(4) The Trained Person designated by condition I.GG.1.b.(3) shall sign and date the records required inI.GG.1.c.(2) of specific measures taken in accordance with a Fugitive Dust Control Plan for each day of operation of the plant. [s. 285.65(3), Wis. Stats.]

(5) The permittee shall ensure that records of the Trained Person designated by conditionI.GG.1.b.(4)'s training or Method 9 certification or other training or qualifications are available at the plant at all times of operation. [s. 285.65(3), Wis. Stats.]

(6) The permittee shall record the start and end times of the process to demonstrate compliance with condition I.GG.1.a.(2). [s. 285.65(3), Wis. Stats.]</td></tr>
</table>

Note 1: When trained staff observe visible emissions at the process itself of 10% or more, or at the property fence line of 5% or more, the trained staff will initiate actions to control fugitive emissions. The actions could include increased watering, increased application of dust suppressants, or increased street s sweeping depending upon the nature of the emissions.

HH. F134 – Facility Haul Roads	
Pollutant: 1. Fugitive Dust (PM/PM10)	
a. Limitations: The permittee shall apply Best Available Control Technology (BACT). BACT shall be met by the use a) paving the haul roads. b) Use of trucks washing stations and c) of a high efficiency vacuum street sweeper. [s. NR 405.08, Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(3), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) All facility haul roads shall be paved to meet the BACT limits. [s. NR 405.08, Wis. Adm. Code] (2) All facility haul roads shall be vacuum swept, at minimum, twice daily (except when weather conditions exist such that precipitation and/or ambient temperature would control fugitive emissions or prevent vacuum sweeping's effectiveness). If, in the opinion of the trained person additional roadways vacuum sweeping is necessary to prevent inappropriate fugitive dust emissions it will be conducted as soon as practical. [s. NR 405.08, Wis. Adm. Code] (3) Truck washing stations shall be installed and used near four locations where removal of mud, dirt and dust must occur, the SCPC ash loading stations, the IGCC slag loading station, the fuel ash reclaim area, and the Caledonia landfill area. [s. NR 405.08, Wis. Adm. Code] (4) The permittee shall identify at least one Trained Person designated to monitor compliance, in accordance with this permit, with the Fugitive Dust Control Plan. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall ensure that the trained Person at the site keep(s) daily records consisting of the date and time roadway sweeping occurred or the date and reasons why it did not. [s. 285.65(3), Wis. Stats., s. NR 415.04(1)(b), Wis. Adm. Code]

II. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 - Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 2. The following emission limits apply to each IGCC Combustion Turbine.	
Pollutant: 1. Particulate Matter Emissions	
a. Limitations: (1) The emissions may not exceed 0.011 pound per million Btu including startup and shut down. (BACT); (2) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.32 [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall perform the compliance emission tests required under condition I. II.1.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 275.0 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 20.0 feet. [s. 285.65(3), Stats., s. NR 406.10, Wis. Adm. Code] (4) The permittee shall fire only fire syngas as the primary fuel with fuel oil having a maximum sulfur content of 0.003% sulfur by weight for start up. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (5) The permittee shall demonstrate good combustion practices by: (a) monitoring appropriate combustion operating parameters. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, test procedures in US EPA Method 5, including backhalf (Method 202) or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. (s. NR 439.04(1)(d), Wis. Adm. Code) (2) During operation, the facility will monitor and record the following operating parameters on an hourly basis: (a) Combustion turbine inlet temperature (b) Combustion turbine firing temperature (c) Combustion turbine exhaust temperature (d) Coal fuel flow rate [s. 285.65(10), Wis. Stats.] (4) During initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.II.1.c.(3) to establish normal operational ranges for use as a compliance demonstration. [s. 285.65(10), Wis. Stats.] (5) The permittee shall install, calibrate, and maintain instrumentation to monitor the parameters identified by condition I.II.1.c.(3)a. – d. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

32 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

I.II. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 - Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 2. The following emission limits apply to each IGCC Combustion Turbine.	
Pollutant: 2. Particulate Matter Emissions less than 10 microns (PM10)	
a. Limitations: (1) The emissions may not exceed 0.011 pound per million Btu including startup and shut down. (BACT); (2) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.33 [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall perform the compliance emission tests required under condition I.II.2.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (3) Stack Parameters: These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 275.0 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 20.0 feet. [s. 285.65(3), Stats., s. NR 406.10, Wis. Adm. Code] (4) The permittee shall fire only fire syngas as the primary fuel with fuel oil having a maximum sulfur content of 0.003% sulfur by weight for start up. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (5) The permittee shall demonstrate good combustion practices by: (a) monitoring appropriate combustion operating parameters. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, test procedures in US EPA Method 5, including backhalf (Method 202) or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. (s. NR 439.04(1)(d), Wis. Adm. Code) (3) During operation, the facility will monitor and record the following operating parameters on an hourly basis: (a) Combustion turbine inlet temperature (b) Combustion turbine firing temperature (c) Combustion turbine exhaust temperature (d) Coal fuel flow rate [s. 285.65(10), Wis. Stats.] (4) During initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.II.2.c.(3) to establish normal operational ranges for use as a compliance demonstration. [s. 285.65(10), Wis. Stats.] (5) The permittee shall install, calibrate, and maintain instrumentation to monitor the parameters identified by condition I.II.2.c.(3)a. – d. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

33 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

<table>
<tr><td colspan="2">II. S39, B39 – Integrated Gasification Combined Cycle (IGCC) 1; S40, B40 – Integrated Gasification Combined Cycle (IGCC) 2. The following emission limits apply to each IGCC Combustion Turbine.</td></tr>
<tr><td colspan="2">Pollutant: 3. Sulfur Dioxide Emissions</td></tr>
<tr><td colspan="2">a. Limitations: (1) (a) 0.015 percent by volume at 15% O2 on a dry basis. (NSPS) [s. NR 440.50(4)(a), Wis. Adm. Code]; or (b) fuel sulfur content less than or equal to 0.8% by weight. (NSPS) [s. NR 440.50(4)(b), Wis. Adm. Code]; (2) 0.03 pound per million Btu heat input, based on a 24-hour average including startup and shut down. (BACT) [s. NR 405.08(2), Wis. Adm. Code]; (3) 40 ppmvd sulfur in the gasified (syngas) fuel (expressed as hydrogen sulfide). (BACT) [s. NR 405.08(2), Wis. Adm. Code; (4) 278 tons in any 12 consecutive months for all periods, including startup and shut down, (BACT) [s. 405.08(2), Wis. Adm. Code]; (5) The sulfur content of fuel oil to be sued during periods of start-up and shut down may not exceed 0.003% by weight. (BACT) [s. NR 405.08(2), Wis. Adm. Code]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.34 [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall perform the compliance emission tests required under condition I. II.3.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(3) <u>Stack Parameters</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 275.0 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 20.0 feet. [s. 285.65(3), Stats., s. NR 406.10, Wis. Adm. Code]

(4) Each combustion turbine may only be fired on syngas, except for periods of startup and load stabilization when distillate fuel oil may also be utilized as a fuel. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(5) Sulfur Dioxide Emission shall be controlled by a syngas cleanup system. [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.20(4)(a)1., Wis. Adm. Code]

(6) Compliance with the sulfur dioxide emission limit contained in I.II.3.a. (3) shall be demonstrated either through the use of (a) daily syngas sampling and analysis or (b) through the use of a sulfur dioxide continuous emission monitoring system (CEMs). [s. NR 405.08(2), Wis. Adm. Code]

(6) Compliance with the sulfur dioxide BACT emission limit contained in I.II3.a.(3) constitutes compliance with the emission limit contained in I.II.3.a.(1) and (2) as I.II.3.a.(3) is a more restrictive limit. [s. 285.65(3), Wis. Stats.]

(7) The sulfur content of fuel oil to be used during periods of start-up and load stabilization may not exceed 0.003% by weight. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]</td><td>(1) <u>Reference Test Method for Sulfur Dioxide Emissions:</u> Whenever compliance emission testing is required, test procedures in US EPA Method 6, 6A or 6C or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(2), Wis. Adm. Code]

(2) The daily syngas sampling and analysis provisions of I.II.3.b.(5)(a) shall be determined according to ASTM D1072-90, “Standard Test Method for Total Sulfur in Fuel Gases”, ASTM D4468-85 “Standard test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Radiometric Colorimetry”, ASTM D5504-94 “Standard test Method for Determination of Sulfur Compound in Natural Gas and gaseous Fuels by Gas Chromatography and Chemiluminescence”, or ASTM 3246-81 “Standard test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry”. [s. NR 439.08(2)(b), Wis. Adm. Code]

(3) The provision of I.II.3.b.(5)(b) shall be satisfied through the installation and use of a continuous emissions monitoring system (CEMs) for sulfur dioxide and carbon dioxide or oxygen content of the flue gases at each location where sulfur dioxide emissions are monitored within 60 days after initial startup of the combustion turbine. The CEMs shall be calibrated within 90 days after initial startup of the combustion turbine. Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 75 and s. NR 439.06(6)(b), Wis. Adm. Code requirements. [s. 285.65(3), Wis. Stats., s. NR 439.06, Wis. Adm. Code]

(4) Continuous emission monitoring methods and procedures shall comply with the requirements of s. NR 439.09, Wis. Adm. Code. [s. NR 439.09, Wis. Adm. Code]

(5) The sulfur content provisions of I.II.3.b.(7) shall be determined according to ASTM D129-95, Standard Test Method for Sulfur in Petroleum Products, ASTM D1552-95, Standard test Method for Sulfur in Petroleum Products, or ASTM D4294-98 Standard test Method for Sulfur in Petroleum Products by Energy-Dispersive X-ray Fluorescence Spectroscopy, respectively. [s. NR 439.08(2)(b), Wis. Adm. Code]

(6) The permittee shall comply with NSPS monitoring of operations requirements per s. NR 440.50(5), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 440.50(5), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(7) The permittee shall use test methods and procedure per s. NR 440.50(6), Wis. Adm. Code to comply with the NSPS emission limits. [s. NR 440.50(6), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]</td></tr>
</table>

34 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

II. **S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 - Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 2. The following emission limits apply to each IGCC Combustion Turbine.**	
Pollutant: 4. Nitrogen Oxides Emissions	
Limitations: (1) The emissions may not exceed 15 ppmdv, corrected to 15% oxygen on a 30 day rolling average basis, not including periods of startup and shut down, on a 30 day rolling basis. (BACT); (2) The emissions may not exceed 15 ppmdv, corrected to 15% oxygen on a 30 day rolling average basis, including periods of startup and shut down, averaged over any consecutive 12 month period. (BACT); (3) 75 ppm @ 15% Oxygen. (NSPS); (3) The use of a diluent injection system (DIS) (BACT). [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.50(3), Wis. Adm. Code, s. NR 428.04(2)(g)3., Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.35 [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall perform the compliance emission tests required under condition I.II.4.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (3) <u>Stack Parameters</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 275.0 feet above ground level. [s. 285.65(3), Wis. Stats. , s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 20.0 feet. [s. 285.65(3), Stats., s. NR 406.10, Wis. Adm. Code] (4) Nitrogen Oxides Emission shall be controlled by a diluent injection system to meet BACT limits. [s. NR 405.08(2), Wis. Adm. Code] (5) The permittee shall demonstrate compliance with the nitrogen oxides emission limit contained in I.II.4.a.(1) using emissions data measured by the continuous emission monitoring system required by I.II.4.c.(2) as follows: (a) Daily average concentration shall be calculated each calendar day by combining the nitrogen oxides concentration and diluent concentration (in % O2 or % CO2) measurement consistent with the procedures specified in 40 CFR 75 Appendix F. [s. 285.65(10), Wis. Stats.] (b) Each monthly nitrogen oxide emissions average shall be calculated by dividing the sum of all daily averages calculated during the month by the number of daily average calculated during the month. [s. 285.65(3), Wis. Stats.] (c) Each 12-month nitrogen oxide emissions average shall be calculated as the average of the past 12 monthly emissions average. [s. 285.65(3), Wis. Stats.] (6) Compliance with the nitrogen oxides BACT emission limit contained in I.II.4.a.(1) constitutes compliance with the NSPS emission limit as the BACT emission limits is more restrictive then the NSPS emission limit. [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Nitrogen Oxides Emissions:</u> Whenever compliance emission testing is required, test procedures in US EPA Method 7or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(6), Wis. Adm. Code] (2) The permittee shall install and operate continuous emissions monitoring system (CEMs) for NOx and carbon dioxide or oxygen within 60 days after initial start up of IGCC. The CEMs shall be calibrated within 90 days after initial start up of the IGCC. Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 75 and s. NR 439.06(6)(b), Wis. Adm. Code requirements. [s. 285.65(3), Wis. Stats., s. NR 439.06, Wis. Adm. Code] (3) Continuous emission monitoring methods and procedures shall comply with the requirements of s. NR 439.09, Wis. Adm. Code. [s. NR 439.09, Wis. Adm. Code] (4) The permittee shall comply with the general and specific monitoring requirements under s. NR 428.04(3)(a) and (b), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (5) The permittee shall comply with all the recordkeeping and reporting requirements under s. NR 428.04(4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(4), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (6) The permittee shall comply with all the requirements for monitoring, installation, certification, data accounting, compliance dates and reporting data prior to initial certification as required under s. NR 428.07(1)(b), Wis. Adm. Code, s. NR 428.07(2)(b)2, Wis. Adm. Code, s, NR 428.07(3), Wis. Adm. Code. [s. 285.65(3), Wis. Stats.] (7) The permittee shall monitor NOx and heat input per s. NR 428.08(1)(e), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (8) The permittee shall submit quarterly reports per s. NR 428.09(2), (3) and (4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(9), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

35 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

II**. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 2. The following emission limits apply to each IGCC Combustion Turbine.**	
Pollutant: 4. Nitrogen Oxides Emissions [CONTINUED]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(7) The permittee shall keep track of the startup and shut down time by monitoring the fuel combusted in the turbine. Startup periods begin with the firing of any fuel in the combustion turbine, and end with the introduction of syngas to the combustion turbine. Shut down period begin with the cessation of syngas flow to the combustion turbine, and end with the cessation of all fuel firing.[s. 285.65(3), Wis. Stats.]	(9) The permittee shall comply with NSPS monitoring of operations requirements per s. NR 440.50(5), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 440.50(5), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (10) The permittee shall use test methods and procedure per s. NR 440.50(6), Wis. Adm. Code to comply with the NSPS emission limits. [s. NR 44.50(6), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (11) The permittee shall keep records required under condition I.II.4.b.(5)(b), (c) and I.II.4.b.(7). [s. 285.65(3), Wis. Stats.]

<table>
<tr><td colspan="2">II. S39, B39 – Integrated Gasification Combined Cycle (IGCC) Combustion Turbine 1; S40, B40 – Integrated Gasification Combined Cycle (IGCC) Combustion Turbine 2.
The following emission limits apply to each IGCC Combustion Turbine.</td></tr>
<tr><td colspan="2">Pollutant: 5. Carbon Monoxide Emissions</td></tr>
<tr><td colspan="2">a. Limitations: (1) The emissions may not exceed 0.030 pound per million Btu on a 24-hour rolling average, excluding periods of startup and shut down. (BACT); (2) The use of good combustion practices. (BACT) ; (3) 624 pounds per hour during any one hour period, including startup and shut down. (4) 282 tons in any 12 consecutive months for all periods, including startup and shut down. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[36] [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall perform the compliance emission tests required under condition I. II.5.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(3) Carbon Monoxide Emissions shall be controlled using good combustion practices to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code]

(4) The permittee shall demonstrate compliance with the BACT limit by:(a) monitoring appropriate combustion operating parameters or (b) through the use of a CO CEMs. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(5) The permittee shall demonstrate compliance with the carbon monoxide emission limits using data from a continuous emissions monitoring system (CEMs) for CO and carbon dioxide or oxygen required under condition I.II.5.c.5 as follows:
(a) Daily average shall be determined by calculating the arithmetic average of all applicable hourly emission rates for a calendar day.
(b) The hourly emission rate shall be calculated by combining the CO concentration and diluent concentration (in % O2 or % CO2) measurement consistent with the procedures specified in 40 CFR Part 75 Appendix F. The conversion factor, (k), shall be 0.7266 x 10-7 lb CO/ft3 - ppm.
(c) The annual emission limit in I.II.a.(4) shall be calculated using and totally the hourly calculated emission rate. [s. 285.65(3), Wis. Stats.]

(6) The permittee shall keep track of the startup and shut down time by monitoring the fuel combusted in the turbine. Startup periods begin with the firing of any fuel in the combustion turbine, and end with the introduction of syngas to the combustion turbine. Shutdown periods begin with the cessation of syngas flow to the combustion turbine, and end with the cessation of all fuel firing. [s. 285.65(3), Wis. Stats.]</td><td>(1) <u>Reference Test Method for Carbon Monoxide Emissions:</u> Whenever compliance emission testing is required, test procedures in US EPA Method 10 or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(4), Wis. Adm. Code]

(2) During operation, the facility will monitor and record the following operating parameters on an hourly basis:
(a) Combustion turbine inlet temperature
(b) Combustion turbine firing temperature
(c) Combustion turbine exhaust temperature
(d) Coal flow rate
[s. 285.65(10), Wis. Stats.]

(3) During initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.II.5.c.(2) to establish normal operational ranges for use as a compliance demonstration. [s. 285.65(10), Wis. Stats.]

(4) The permittee shall install, calibrate, and maintain instrumentation to monitor the parameters identified by condition I.II.1.c.(3)a. – d. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(5) The permittee shall install and operate continuous emissions monitoring system (CEMs) for CO and carbon dioxide or oxygen within 60 days after initial start up of IGCC. The CEMs shall be calibrated within 90 days after initial start up of the IGCC. Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 75 and s. NR 439.06(6)(b), Wis. Adm. Code requirements. [s. 285.65(3), Wis. Stats., s. NR 439.06, Wis. Adm. Code]

(6) Continuous emission monitoring methods and procedures shall comply with the requirements of s. NR 439.09, Wis. Adm. Code. [s. NR 439.09, Wis. Adm. Code]

(7) The permittee shall keep records required under condition I.II.5.b.(5)(b), (c) and I.II.5.b.(6). [s. 285.65(3), Wis. Stats.]</td></tr>
</table>

[36] If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

I**I. S39, B39 – Integrated Gasification Combined Cycle (IGCC) Combustion Turbine 1; S40, B40 – Integrated Gasification Combined Cycle (IGCC) Combustion Turbine 2. The following emission limits apply to each IGCC Combustion Turbine.**	
Pollutant: 6. Volatile Organic Compound Emissions	
a. Limitations: (1) 0.0017 pound per million Btu heat input excluding periods of startup and shut down averaged over any consecutive 24-hour period. Startup periods begin with the firing of any fuel in the combustion turbine, and end with the introduction of syngas to the combustion turbine. Shutdown periods begin with the cessation of syngas flow to the combustion turbine, and end with the cessation of all fuel firing. (LAER); (2) 3.64 pounds per hour excluding periods of startup and shut down, averaged over any consecutive 24-hour period. (LAER); (3) 16.93 tons in any 12 consecutive months for all periods, including startup and shut down. (LAER); (4) The use of good combustion practices. (LAER) [s. NR 408.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.37 [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall perform the compliance emission tests required under condition I.II.6.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (3) Volatile Organic Compound Emissions shall be controlled using good combustion practices to meet LAER emission limit. [s. NR 408.08(2), Wis. Adm. Code] (4). The permittee shall demonstrate compliance with the LAER limit by: (a) monitoring appropriate combustion operating parameters or (b) through the use of a CO CEMs. [s. 285.65(3), Wis. Stats., s, 285.65(10), Wis. Stats.] (5) CO emissions data measured by the CEM system shall be used to demonstrate compliance with the LAER emission limit by using the following equation to keep daily, monthly and annual VOC emissions records: VOC actual = VOC limit X (CO actual/CO limit) [s. 285.65(3), Wis Stats., s. 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for VOC Emissions:</u> Whenever compliance emission testing is required, test procedures in US EPA Method 25 or 18 or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(1), Wis. Adm. Code] (2) During operation, the facility will monitor and record the following operating parameters on an hourly basis: (a) Combustion turbine inlet temperature (b) Combustion turbine firing temperature (c) Combustion turbine exhaust temperature (d) Coal flow rate [s. 285.65(10), Wis. Stats.] (3) During initial performance testing, the permittee shall perform simultaneous monitoring of the parameters identified in condition I.II.5.c.(2) to establish normal operational ranges for use as a compliance demonstration. [s. 285.65(10), Wis. Stats.] (4) The permittee shall install, calibrate, and maintain instrumentation to monitor the parameters identified by condition I.II.5.c.(3)a. – b. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (5) The permittee shall install and operate continuous emissions monitoring system (CEMs) for CO and carbon dioxide or oxygen within 60 days after initial start up of IGCC. The CEMs shall be calibrated within 90 days after initial start up of the IGCC. Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 75 and s. NR 439.06(6)(b), Wis. Adm. Code requirements. [s. 285.65(3), Wis. Stats., s. NR 439.06, Wis. Adm. Code] (6) Continuous emission monitoring methods and procedures shall comply with the requirements of s. NR 439.09, Wis. Adm. Code. [s. NR 439.09, Wis. Adm. Code] (7) The permittee shall keep records required under condition I.II.6.b.(5). [s. 285.65(3), Wis. Stats.]

37 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

II. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 - Integrated Gasification Combined Cycle Combustion turbine (IGCC) 2. The following emission limits apply to each IGCC Combustion Turbine.	
Pollutant: 7. Lead Emissions	
a. Limitations: (1) The emissions may not exceed 0.0000257 pound per million Btu including startup and shut down. (BACT); (2) The use of good combustion practices. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.38 [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall perform the compliance emission tests required under condition I.II.7.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (3) Lead Emissions shall be controlled using good combustion practices and firing syngas as the primary fuel with 0.003% low sulfur fuel for startup to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (4). The permittee shall demonstrate compliance with the BACT limit by complying with the conditions in I.II.1.b. [s. 285.65(3), Wis. Stats.; s, 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for Lead Emissions:</u> Whenever compliance emission testing is required, test procedures in US EPA Method 12, or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code]

38 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

I**I. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 2. The following emission limits apply to each IGCC Combustion Turbine.**	
Pollutant: 8. Mercury Emissions	
a. Limitations: (1) The emissions may not exceed 0. 56lb/trillion Btu based on a 12-month rolling average including startup and shut down. (BACT); (2) The use of carbon bed or equivalent control technology capable of achieving 95% control of mercury emissions. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.39 [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall perform the compliance emission tests required under condition I.II.8.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (3) Mercury Emissions shall be controlled using Carbon bed or filter containing similar material in the synthetic gas specifically designed to control emissions of mercury contained in the fuel supply or such requirement for the effective control of mercury emissions as may be promulgated by USEPA as the MACT standard applicable to new stationary combustion turbines of an IGCC facility to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (4) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the carbon bed and (b) A list of items that will be checked and maintained and their frequency, to ensure that the carbon bed system is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (5) The permittee shall monitor uncontrolled mercury emissions through coal sampling and analysis. Such testing occur on a monthly basis according to the relevant provisions of s. NR 439.08, Wis. Adm. Code as applied to mercury content in the coal. The permittee shall also monitor monthly average coal higher heating value. [s. NR 405.08, Wis. Adm. Code]	(1) <u>Reference Test Method for Mercury Emissions:</u> Whenever compliance emission testing is required, test procedures in US EPA Method 29 or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall record information on the maintenance required in condition I.II.8.b.(4). [s. NR 439.04(1)(a)6, Wis. Adm. Code] (3) The data obtained form the mercury content from the coal sampling and analysis shall be kept at the facility for a period of five years. [s. 285.65(3), Wis. Stats.]

Note 1: The BACT Limit for Mercury is based on uncontrolled mercury emissions of 11.2 pounds per trillion Btu and a control efficiency of 95%.

39 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

II. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 - Integrated Gasification Combined Cycle Combustion turbine (IGCC) 2.
The following emission limits apply to each IGCC Combustion Turbine.

Pollutant: 9. Visible Emissions

a. Limitations: 20% opacity. [s. NR 431.05, Wis. Adm. Code]

b. Compliance Demonstration:	c. Test Methods, Recordkeeping, and Monitoring:
(1) Opacity shall be controlled using good combustion practices. [s. 285.65(3), Wis. Stats.] (2) The compliance demonstration methods identified in I.II.1.b. shall be used to demonstrate compliance with the visible emission limit. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 or Reference Method 22 of Appendix A, 40 CFR Part 60 shall be used to demonstrate compliance or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall install, calibrate, maintain and operate a continuous monitoring system, and record the output to the system, for measuring the opacity of emissions discharged to the atmosphere. [s. 285.65(10), Wis. Stats.] (3) Continuous opacity monitoring methods and procedures shall comply with the requirements of s. NR 439.09, Wis. Adm. Code. [s. NR 439.09, Wis. Adm. Code]

II. S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 - Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 2. The following emission limits apply to each IGCC Combustion Turbine.	
Pollutant: 10. Hazardous air pollutants (inorganic solid HAPs, inorganic acid HAPs, Organic HAPs) regulated under sec. 112 of the Clean Air Act.	
a. Limitations: (1) The permittee shall use syngas cleanup system and use good combustion practices to meet case by case MACT for inorganic solid HAPs; (2) The permittee shall use syngas cleanup system and good combustion practices to comply with the case by case MACT limits for inorganic acid HAPs; (3) The permittee shall comply with good combustion practices and meet the VOC emission limits to comply with case by case MACT for organic HAPs. [s. 285.65(13), Wis. Stats., s. 285.65(3), Wis. Stats., 40 CFR Part 63, Subpart B]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The inorganic solid HAPs, acid gas HAPs and organic HAPs shall be controlled using a syngas clean up system and good combustion practices. [s. 285.65(3), Wis. Stats.] (2) The compliance demonstration methods in I.II.1.b., I.II.3.b., I.II.6.b., shall be used as compliance demonstration techniques for inorganic solid HAPs, inorganic acid HAPs, and organic HAPs. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]	(1) <u>Reference Test Method for organic HAPs Emissions; inorganic solid HAPs, and inorganic acid HAPs:</u> Whenever compliance emission testing is required an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code] (2) The testing, recordkeeping and monitoring requirements contained in I.II.1.c., I.II.3.c. shall be used as compliance methods for I.II.10.b.(2). [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

II. **S39, B39 – Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 1; S40, B40 - Integrated Gasification Combined Cycle Combustion Turbine (IGCC) 2.** The following emission limits apply to each IGCC Combustion Turbine.	
Pollutant: 11. Sulfuric Acid Mist	
Limitations: (1) The emissions may not exceed 0.0005 pound per million Btu, based on a 3-hour average including startup and shut down. (BACT); (2) The use of gas clean up system. (BACT) [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) (1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.40 [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall perform the compliance emission tests required under condition I. II.11.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (3) Sulfuric acid mist emissions shall be controlled by a gas clean up system. [s. NR 405.08(2), Wis. Adm. Code] (4) The compliance demonstration method identified in section I.II.3.b. shall be used as compliance demonstration techniques for sulfuric acid mist emission limitation. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Sulfur Acid Mist Emissions: Whenever compliance emission testing is required, US EPA Method 8 shall be used to demonstrate compliance or an alternative method approved in writing by the department, shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code]

40 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

<table>
<tr><td colspan="2">JJ. S41, P41 – Sulfuric Acid Plant #1; S42, P42, Sulfuric Acid Plant #2
The following emissions limits apply to each sulfuric acid plant.</td></tr>
<tr><td colspan="2">Pollutant: 1. Sulfur Dioxide Emissions</td></tr>
<tr><td colspan="2">a. Limitations: (1) The emissions may not exceed 4.0 pounds per tons of 100% sulfuric acid produced. (BACT); (2) The use of a dual absorption plant and fiber mist eliminators to meet BACT limits. [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.24(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.41 [s. NR 439.07, Wis. Adm. Code]

(2) The permittee shall perform the compliance emission tests required under condition I.JJ.1.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(3) <u>Stack Parameters</u> These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 150.0 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 3.5 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(4) The permittee shall control sulfur dioxide emissions through the use of a dual absorption plan and fiber mist eliminator. [s. NR 405.08(2), Wis. Adm. Code]

(5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fiber mist eliminator and (b) A list of items that will be checked and maintained and their frequency, to ensure that the dual absorption plan and fiber mist eliminator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]</td><td>(1) R<u>eference Test Method for Sulfur Dioxide Emissions:</u> Whenever compliance emission testing is required, US EPA Method 6, 6A, 6C or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(2), Wis. Adm. Code]

(2) The permittee shall record information on the maintenance required in condition I.JJ.1.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

(3) The permittee shall install and operate continuous emissions monitoring system (CEMs) for sulfur dioxide within 60 days after initial start up of the sulfuric acid plant. The CEMs shall be calibrated within 90 days after initial start up of the sulfuric acid plant. Continuous emissions monitoring systems shall be installed and operated in accordance with 40 CFR Part 60 and s. NR 439.06(6)(b), Wis. Adm. Code requirements. A copy of s. NR 440.24, Wis. Adm. Code requirements attached with the permit. [s. 285.65(3), Wis. Stats., s. NR 440.24(5), Wis. Adm. Code, s. NR 439.06, Wis. Adm. Code]

(4) Continuous emission monitoring methods and procedures shall comply with the requirements of s. NR 440.24(5) and (6), Wis. Adm. Code and s. NR 439.09, Wis. Adm. Code. A copy of s. NR 440.24, Wis. Adm. Code requirements attached with the permit. [s. NR 439.09, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(5) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]</td></tr>
</table>

Note 1: The sulfuric acid plant is subject to New Source Performance Standards (NSPS) for sulfur dioxide. The sulfur dioxide emissions limit to not exceed 4.0 pounds per tons 100% sulfuric acid produced per s. NR 440.24(3), Wis. Adm. Code. The sulfuric acid plant is expected to comply with the sulfur dioxide emission limits under NSPS.

41 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

JJ. S41, P41 – Sulfuric Acid Plant #1; S42, P42, Sulfuric Acid Plant #2 The following emissions limits apply to each sulfuric acid plant.	
Pollutant: 2. Sulfur Acid Mist Emissions	
a. Limitations: (1) The emissions may not exceed 0.128 pounds per tons. (BACT).; (2) The use of a dual absorption plant and fiber mist eliminators to meet the BACT limits. [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.24(4)(a), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.42 [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall perform the compliance emission tests required under condition I.JJ.2.b.(1) every 24 months from the date of the last stack test as long as the permit remains valid. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (3) The permittee shall control sulfuric acid mist emissions through the use of a dual absorption plan and fiber mist eliminator. [s. NR 405.08(2), Wis. Adm. Code] (4) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the fiber mist eliminator and (b) A list of items that will be checked and maintained and their frequency, to ensure that the dual absorption plan and fiber mist eliminator is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s, 285.65(10), Wis. Stats.] (5) The permittee shall determine compliance with sulfuric acid emission limits per test methods and procedures identified in s. NR 440.24(6)(b), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Sulfuric Acid Mist Emissions: Whenever compliance emission testing is required, US EPA Method 8 or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall record information on the maintenance required in condition I.JJ.2.b.(4). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

Note 1: The sulfuric acid plant is subject to New Source Performance Standards (NSPS) for sulfuric acid mist emissions. The sulfuric acid mist emissions limit to not exceed 0.15 pounds per tons 100% sulfuric acid produced per s. NR 440.24(4)(a), Wis. Adm. Code. The BACT limit for sulfuric acid mist is more restrictive then the NSPS limit for sulfuric acid mist. The sulfuric acid plant is expected to meet the NSPS limit for sulfuric acid mist.

42 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

JJ. S41, P41 – Sulfuric Acid Plant #1; S42, B42, Sulfuric Acid Plant #2 The following emissions limits apply to each sulfuric acid plant.	
Pollutant: 3. Visible Emissions	
a. Limitations: 10% opacity [s. NR 405.09, Wis. Adm. Code, s. NR 440.24(4)(a), Wis. Adm. Code, s. NR 431.05, Wis. Adm. Code, s. 285.65(13), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Compliance emission tests to demonstrate compliance with the visible emission limit shall be conducted within 60 days after the start of the initial operation. [s. 285.65(3), Wis. Stats.] (2) The permittee shall determine compliance with visible emission limits per test methods and procedures identified in s. NR 440.24(6)(b)4., Wis. Adm. Code. A copy of these requirements attached with the permit. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

<table>
<tr><td colspan="2">KK. S43, P43 – Gasifier Flare</td></tr>
<tr><td colspan="2">Pollutant: 1. Particulate Matter Emissions (PM/PM10)</td></tr>
<tr><td colspan="2">a. Limitations: (1) The use of good flare design and limiting number of startup and shut down cycles to 35 per 12 contiguous month period to meet BACT. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) <u>Stack Parameters</u>. These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed.

(a) The stack height shall be at least 150.0 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code]

(b) The stack inside diameter at the outlet may not exceed 6.0 feet. [s. 285.65(3), Stats., s. NR 406.10, Wis. Adm. Code]

(2) The flare shall be operated at all times when the IGCC unit is operating. [s. 285.65(3), Wis. Stats.]

(3) The permittee shall limit the number of startup and shut down cycles to 35 per 12 contiguous month period. [s. NR 405.08(2), Wis. Adm. Code]

(4) The permittee shall install and operate a temperature monitoring and continuous recording system to ensure that the flare is operating. [s. NR 405.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.]</td><td>(1) The permittee shall retain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code]

(2) The permittee shall record the number of startup and shut downs to demonstrate compliance with condition I.KK.1.b.(3). [s. NR 439.06(1), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

(3) The permittee shall record date and time the flare was inoperable for each event the flare was inoperable. [s. 285.65(3), Wis. Stats.]</td></tr>
</table>

KK. S43, P43 – Gasifier Flare	
Pollutant: 2 Visible Emissions	
a. Limitations: 0% opacity or number 1 on the Ringlemann chart. See Note 1 [s. NR 431.05, Wis. Adm. Code, s. NR 405.08, Wis. Adm. Code, s. 285.65(13), Wis. Stats., s. NR 440.18(3)(a), Wis. Adm. Code]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Compliance emission tests to demonstrate compliance with the visible emission limit shall be conducted within 180 days after the start of the initial operation. [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Visible Emissions: Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(9)(a)1., Wis. Adm. Code]

Note 1: S. NR 440.18(3)(a), Wis. Adm. Code requires flares to be designed and operated with no visible emissions as determined by the methods specified in s. NR 440.18(6), Wis. Adm. Code except for periods not to exceed a total of five minutes during any 2 consecutive hours.

LL. B44, S44 – IGCC Auxiliary Boiler	
Pollutant: 1 Particulate Matter	
b. Limitations: (1) The emissions may not exceed 0.007 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.020 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.207(4) (c), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.[43] [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall determine the hourly emissions using fuel consumption records and emissions factor determined by stack testing. [s. 285.65(3), Wis. Stats.] (3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 140.0 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 4.0 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (4) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (6) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.1.a. (4). [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR 60 and US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall keep records on the heat input used as required in condition I.LL.1.b.(6). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) The permittee shall record information on the maintenance required in condition I.LL.1.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

Note 1: The IGCC auxiliary boiler is subject to NSPS requirements for particulate matter (PM) under s. NR 440.207(4)(c), Wis. Adm. Code. The only New Source Performance Standards (NSPS) standard that will be applicable to the boiler for PM is in the form of an opacity standard when fuel oil is fired per s. NR 440.207(4)(c), Wis. Adm. Code.

43 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

LL. S44, B44 – IGCC Auxiliary Boiler	
Pollutant: 2. Particulate Matter Emissions less than 10 microns (PM_{10})	
Limitations: (1) The emissions may not exceed 0.007 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.020 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) Initial compliance emission tests shall be conducted within 180 days after the start of operation of the process to show compliance with the emission limitation.44 [s. NR 439.07, Wis. Adm. Code] (2) The permittee shall determine the hourly emissions using fuel consumption records and emissions factor determined by stack testing. [s. 285.65(3), Wis. Stats.] (3) Stack Parameters These requirements are included because the source was reviewed with these stack parameters and it was determined that no increments or ambient air quality standards will be violated when constructed as proposed. (a) The stack height shall be at least 140 feet above ground level. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (b) The stack inside diameter at the outlet may not exceed 4.0 feet. [s. 285.65(3), Wis. Stats., s. NR 406.10, Wis. Adm. Code] (4) The permittee shall fire natural gas and/or fuel having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (5) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (6) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.2.a. (4). [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Particulate Matter Emissions: Whenever compliance emission testing is required, US EPA Method 5, including backhalf (Method 202) shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep and maintain on site technical drawings, blueprints or equivalent records of the physical stack parameters. [s. NR 439.04(1)(d), Wis. Adm. Code] (3) The permittee shall keep records on the heat input used as required in condition I.LL.2.b.(6). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (4) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (5) The permittee shall record information on the maintenance required in condition I.LL.2.b.(5). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

44 If the compliance emission tests cannot be conducted within 180 days after the start of initial operation, the permit holder may request and the Department may approve, in writing, an extension of time to conduct the test(s).

LL. S44, B44 – IGCC Auxiliary Boiler	
Pollutant: 3. Sulfur Dioxide	
a. Limitations: (1) The emissions may not exceed 0.0012 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.0032 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. NR 440.207(3)(d), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records, fuel sulfur content and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) A representative sample shall be taken from each fuel lot of fuel oil received. The sample shall be analyzed by the permittee for the sulfur content by weight using procedures outline in s. NR 439.08(2), Wis. Adm. Code and the analysis shall be retained by the permittee for a period of at least five years. [s. 285.65(3), Wis. Stats.] (5) The Department will accept, in lieu of an analysis on each fuel lot under (4) above, an analysis of a representative sample of the fuel lot of distillate fuel oil from which the fuel lot was taken. [s. 285.65(3), Wis. Stats., s. NR 440.207(5)(h), Wis. Adm. Code]	(1) <u>Reference Test Method for Sulfur Dioxide Emissions:</u> Whenever compliance emission testing is required, US EPA Method 6, 6A or 6C shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(2), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.LL.3.b.(8). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.LL.3.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code] (5) The permittee shall keep records required under condition I.LL.3.b.(4) – (7). [s. NR 439.04(1)(d), Wis. Adm. Code] (6) The permittee shall comply with the NSPS reporting and recordkeeping requirements per s. NR 440.207(9), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. 285.65(3), Wis. Stats.] (7) The permittee shall keep records of the fuel supplier certification. The certification shall include the following information: 1. For distillate oil: a. The name of the oil supplier; and b. A statement from the oil supplier that the oil complies with the specification under the definition of distillate oil in s. NR 440.207(2)(g), Wis. Adm. Code [s. 285.65(3), Wis. Stats., s. NR 440.207(9)(f), Wis. Adm. Code]

Note 1: The New Source Performance Standard (NSPS) for sulfur dioxide in s. NR 440.207(3) (d), Wis. Adm. Code will be applicable to the IGCC auxiliary boiler only when fuel oil is fired and is 0.50 pound per million Btu heat input or combust oil having a sulfur content of 0.5 percent by weight. The BACT emission limit for sulfur dioxide is more restrictive then the NSPS limit for sulfur dioxide, thus the IGCC auxiliary boiler is expected to meet the NSPS limit for sulfur dioxide.

LL. S44, B44 – IGCC Auxiliary Boiler	
Pollutant: 3. Sulfur Dioxide (continued)	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(6) The permittee shall retain copies of its distillate fuel oil supplier's fuel sulfur and heat content analyses at the facility for each fuel lot of distillate fuel oil received pursuant to 40 CFR 60.334 for a period of five years. [s. NR 439.04(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (7) The permittee shall further obtain certification from the fuel supplier that the applicable methods in s. NR 439.08(2), Wis. Adm. Code, were followed, if applicable, by the supplier in the preparation of said sulfur and heat content analyses. The fuel lot's quantity of fuel oil shall be included with the copies of these analyses. The fuel supplier certification shall include the information identified in condition I.LL.3.c.(7). [s. 285.65(3), Wis. Stats.] (8) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.3.a. (4). [s. 285.65(3), Wis. Stats.]	

LL. S44, B44 – IGCC Auxiliary Boiler	
Pollutant: 4. Oxides of Nitrogen (NOx)	
a. Limitations: (1) The emissions may not exceed 0.050 pound per million Btu when firing natural gas based on a 30-day rolling average. (BACT); (2) The emissions may not exceed 0.090 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight oil based on a 30-day rolling average. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. NR 428.04(2)(a)2., and 3., Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption record and vendors or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.4.a. (4). [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Nitrogen Oxide Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR 60, US EPA Method 7 or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(6), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.LL.4.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.LL.4.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code] (5) The permittee shall comply with the general and specific monitoring requirements under s. NR 428.04(3)(a) and (b), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(3), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (6) The permittee shall comply with all the recordkeeping and reporting requirements under s. NR 428.04(4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(4), Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (7) The permittee shall comply with all the requirements for monitoring, installation, certification, data accounting, compliance dates and reporting data prior to initial certification as required under s. NR 428.07(1)(b), Wis. Adm. Code, s. NR 428.07(2)(b)2, Wis. Adm. Code, s, NR 428.07(3), Wis. Adm. Code. [s. 285.65(3), Wis. Stats.] (8) The pemittee shall monitor NOx and heat input per s. NR 428.08(1)(a), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.08, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] (9) The permittee shall submit quarterly reports per s. NR 428.09(1), (3) and (4), Wis. Adm. Code. A copy of these requirements attached with the permit. [s. NR 428.04(9), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

Note 1: The IGCC auxiliary boiler is subject to NOx emission limits per s. NR 428.04(2)(a)2. and 3., Wis. Adm. Code and is 0.05 pounds per million Btu of heat input when firing natural gas and 0.09 pounds per million Btu of heat input when firing fuel oil. The BACT limit for NOx is more restrictive then the emission limit for NOx under s. NR 428,04, Wis. Adm. Code, thus the IGCC auxiliary boiler is expected to meet the emission limits for NOx under s. NR 428.04, Wis. Adm. Code.

LL. S44, B44 – IGCC Auxiliary Boiler	
Pollutant: 5. Carbon Monoxide	
a. Limitations: (1) The emissions may not exceed 0.045 pound per million Btu when firing natural gas based on a 30-day rolling average. (BACT); (2) The emissions may not exceed 0.045 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight based on a 30-day rolling average. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 factor or vendor provided emissions factor [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and /or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.5.a. (4). [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Carbon Monoxide Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR Part 60, Appendix A, US EPA Method 10, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(4), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.LL.5.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.LL.5.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

LL. S44, B44 – IGCC Auxiliary Boiler	
Pollutant: 6. Volatile Organic Compounds (VOC)	
(a) Limitations: (1) The emissions may not exceed 0.0060 pound per million Btu when firing natural gas based on a 30-day rolling average. (LAER); (2) The emissions may not exceed 0.0020 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight based on a 30-day rolling average. (LAER); (3) The use of good combustion practices. (LAER); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 408.04, Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor or vendor provided emission factors. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet LAER emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.6.a. (4). [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for VOC Emissions: Whenever compliance emission testing is required, test procedures in 40 CFR Part 60, US EPA Method 25 or 18, or an alternate method approved in writing by the Department shall be used to demonstrate compliance. [s. NR 439.06(3), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.LL.6.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.LL.6.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

LL. S44, B44 – IGCC Auxiliary Boiler	
Pollutant: 7. Lead Emissions	
a. Limitations: (1) The emissions may not exceed 0.000000024 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.000009 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.7.a. (4). [s. 285.65(3), Wis. Stats.]	(1) Reference Test Method for Lead Emissions: Whenever compliance emission testing is required, US EPA Method 12 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(1), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.LL.7.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.LL.7.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

LL. S44, B44 – IGCC Auxiliary Boiler	
Pollutant: 8. Mercury Emissions	
a. Limitations: (1) The emissions may not exceed 0.00000026 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.000003 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.8.a. (4). [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Mercury Emissions:</u> Whenever compliance emission testing is required, US EPA Method 29 or an alternative method approved in writing by the department shall be used to demonstrate compliance. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.LL.8.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.LL.8.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

LL. S44, B44 – IGCC Auxiliary Boiler	
Pollutant: 9. Emissions of Fluorides	
a. Limitations: (1) The emissions may not exceed 0.0000990 pound per million Btu when firing natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (2) The use of good combustion practices. (BACT); (3) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall determine the hourly emissions using fuel consumption records and AP-42 emissions factor. [s. 285.65(3), Wis. Stats.] (2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler and (b) A list of items that will be checked and maintained and their frequency, to ensure that the boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.9.a. (3). [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Emissions of Fluorides:</u> Whenever compliance emission testing is required, US EPA Method 13B shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] (2) The permittee shall keep records on the heat input used as required in condition I.LL.9.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall record information on the maintenance required in condition I.LL.9.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]

LL. S44, B44 – IGCC Auxiliary Boiler	
Pollutant: 10. Visible Emissions	
a. Limitations: 20% opacity or number 1 on the Ringlemann chart. [s. NR 431.05, Wis. Adm. Code, s. NR 440.207(4)(c), Wis. Adm. Code] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (2) The permittee shall conduct an initial test as required under s. NR 440.08, Wis. Adm. Code using the procedures and reference method in 40 CFR part 60, Appendix A, which is incorporated by reference in s. NR 440.17, Wis. Adm. Code. [s. NR 440.207(4)(c), Wis. Adm. Code]	(1) <u>Reference Test Method for Visible Emissions:</u> Whenever compliance emission testing is required, US EPA Method 9 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(9)(a)1., Wis. Adm. Code] (2) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

Note 1: Any gases emitted from the stack when the unit is fired with fuel oil shall not have an opacity greater than 20% (6 minutes average). The exception is one 6-minute period per hour when the opacity not exceeding 27%. The opacity standard does not apply during periods of start up and shut down or malfunction.

<table>
<tr><td colspan="2">LL. S44, B44 – IGCC Auxiliary Boiler</td></tr>
<tr><td colspan="2">Pollutant: 11. Hazardous air pollutants (inorganic solid HAPs, inorganic acid HAPs, Organic HAPs) regulated under sec. 112 of the Clean Air Act.</td></tr>
<tr><td colspan="2">a. Limitations: (1) The permittee shall use natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight and comply with the PM/PM10 limits to meet case by case MACT for inorganic solid HAPs; (2) The permittee shall us natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight to comply with the case by case MACT limits for inorganic acid HAPs; (3) The permittee shall comply with and meet the VOC LAER emission limits to comply with case by case MACT for organic HAPs and (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. 285.65(13), Wis. Stats.]</td></tr>
<tr><td>b. Compliance Demonstration:</td><td>c. Test Methods, Recordkeeping, and Monitoring:</td></tr>
<tr><td>(1) The permittee shall determine the hourly emissions using fuel consumption records and EPRI provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.]

(2) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet MACT emission limit. [s. 285.65(13), Wis. Stats.]

(3) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the boiler; and (b) A list of items that will be checked and maintained and their frequency, to ensure that boiler is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.]

(4) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.11.a. (4). [s. 285.65(3), Wis. Stats.]</td><td>(1) <u>Reference Test Method for organic HAPs Emissions; inorganic solid HAPs, and inorganic acid HAPs:</u> Whenever compliance emission testing is required a method approved in writing by the Department shall be used to demonstrate compliance.
[s. NR 439.06(1), Wis. Adm. Code]

(2) The permittee shall keep records on the heat input used as required in condition I.LL.11.b.(4). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.]

(3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code]

(4) The permittee shall record information on the maintenance required in condition I.L.11.b.(3). [s. NR 439.04(1)(a)6, Wis. Adm. Code]</td></tr>
</table>

LL. S44, B44 – IGCC Auxiliary Boiler	
Pollutant: 12. Sulfuric Acid Mist	
a. Limitations: (1) The emissions may not exceed 0.00024 pound per million Btu when firing natural gas. (BACT); (2) The emissions may not exceed 0.00064 pound per million Btu when firing fuel oil having a maximum sulfur content of 0.003% by weight. (BACT); (3) The use of good combustion practices. (BACT); (4) The total heat input may not exceed 198,000 mmBtu in any 12 consecutive months, of which no more than 49,500 mmBtu may be from the combustion of fuel oil in any 12 consecutive months. [s. NR 405.08(2), Wis. Adm. Code, s. 285.65(3), Wis. Stats., s. 285.65(7), Wis. Stats.]	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall fire natural gas and/or fuel oil having a maximum sulfur content of 0.003% by weight. This condition is established to meet BACT emission limit. [s. NR 405.08(2), Wis. Adm. Code] (2) The permittee shall determine the hourly emissions using fuel consumption records, and vendor provided or AP-42 emission factors. [s. 285.65(3), Wis. Stats.] 3) The permittee shall keep daily records of the type and amount of fuel fired in the boiler and shall calculate heat input to the unit on a daily basis. The heat input used records shall be compiled on an annual basis to show compliance with I.LL.12.a. (4). [s. 285.65(3), Wis. Stats.]	(1) <u>Reference Test Method for Sulfur Acid Mist Emissions:</u> Whenever compliance emission testing is required, US EPA Method 8 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(8), Wis. Adm. Code] 2) The permittee shall keep records on the heat input used as required in condition I.LL.12.b.(3). [s. 285.65(10), Wis. Stats., s. 285.65(3), Wis. Stats.] (3) The permittee shall keep retain on site, plans and specifications that indicate the process's fuel design capabilities. [s. NR 439.04(1)(d), Wis. Adm. Code] (4) The permittee shall keep records required under condition I.LL.3.b.(4) – (7) to demonstrate compliance with the sulfur content in the fuel. [s. NR 439.04(1)(d), Wis. Adm. Code, s. 285.65(3), Wis. Stats.]

MM. T16 – SCPC Boiler Fuel Oil Storage Tank (500,000 gallons), T118 – IGCC Fuel Oil Storage Tank (300,000 gallons), T121 – Diesel Gen. #1 Fuel Oil Storage Tank (5,000 gallons), T122 – Diesel Gen. #2 Fuel Oil Storage Tank (5,000 gallons), T123 - Fire Pump Fuel oil Storage Tank (1,000 gallon), T119, T120 – Two IGCC Sulfuric Acid Storage Tanks The following emission limits apply to each storage tanks, T16, T118, T121, T122, T123.	
Pollutant: 1. Volatile Organic Compounds (VOC)	
a. Limitations: (1) Use of a carbon bed absorption system or its equivalent on each fuel oil storage tanks to meet LAER control requirements. (LAER); (2) 90% reduction in VOC emissions. (LAER) [s. NR 408.02, Wis. Adm. Code, s. 285.65(3), Wis. Stats.] See Note 1	
b. Compliance Demonstration:	**c. Test Methods, Recordkeeping, and Monitoring:**
(1) The permittee shall provide the following information to the Department at least four months prior to the expiration of the construction permit to demonstrate compliance with good combustion practices: (a) A copy of the original equipment manufacturer (OEM) procedures that should be followed to maintain the carbon bed; and (b) A list of items that will be checked and maintained and their frequency, to ensure that carbon bed is operating properly. This information will be used by the Department to establish appropriate permit conditions in the operation permit. [s. 285.65(3), Wis. Stats., s. 285.65(10), Wis. Stats.] (2) Compliance emission tests to demonstrate compliance with the 90% reduction emission limit in I.MM.1.a.(2) shall be conducted within 60 days after the start of the initial operation of tanks T16 and T118. [s. 285.65(3), Wis. Stats.] (3) The maximum true vapor pressure of fuel oil shall be less than 3.5 kPa. The condition is established so the storage tanks are not subject to NSPS requirements. [s. 285.65(7), Wis. Stats.] (4) The permittee may use available data on the Reid pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored fuel oil to determine the maximum true vapor pressure from the nomographs contained in API Publications 2517. [s. 285.65(7), Wis. Stats.]	(1) Reference test Method for Volatile Organic Compound Emissions: Whenever compliance emission testing is required, the appropriate US EPA Method 25 or 18 shall be used to demonstrate compliance or an alternate method approved in writing by the Department, shall be used. [s. NR 439.06(3)., Wis. Adm. Code] (2) The permittee shall record information on the maintenance required in condition I.MM.1.b.(1). [s. NR 439.04(1)(a)6, Wis. Adm. Code] (3) The permittee shall retain records of the determined maximum true vapor pressure. [s, 285.65(7), Wis. Stats.]

Note 1: The standards of performance for a new sources under s. NR 440.285, Wis. Adm. Code apply to al new petroleum storage tanks which are larger than 40 cubic meters (10,600 gallons). Therefore, the new SCPC boiler and IGCC fuel oil storage tanks are subject to the requirements of s. NR 440.285. However the performance standards under this section apply to tanks storing organic liquids with a maximum true vapor pressure greater than 5.2 kPa (0.74 psia). The fuel oil has a maximum true vapor pressure of 0.035 kPa (0.005 psia). As a result, although the SCPC boiler and IGCC fuel oil storage tanks are subject to the performance standards under s. NR 440.285, Wis. Adm. Code there are no applicable NSPS standards for these tanks.

NN. OTHER CONDITIONS APPLICABLE TO THE ENTIRE FACILITY

Condition Type: 1. Construction Permit Requirements

a. Conditions:

(1) Construction Notification: The permittee shall inform the Wisconsin Department of Natural Resources, Southeast Region, 2300 North Dr. Martin Luther King Jr. Drive, Milwaukee, WI 53212, Phone (414) 263-8500, in writing of the following for the emissions unit covered in this permit:

(a) Notice of commencing construction shall be submitted within 15 days of the start of construction.

(b) Notice of intent to initially operate the source(s) covered by this permit, 30 days prior to the anticipated date of initial operation.

(c) Notice of the actual date of initial startutp shall be submitted within 15 days of the initial startup.

[s. NR 439.03(1), Wis. Adm. Code]

(2) (a) Construction Permit Expiration: This construction permit expires 90 months after the date of issuance. Construction or modification and an initial operation period for equipment shakedown, testing and Department evaluation of operation to assure conformity with the permit conditions is authorized for each emissions unit covered in this permit. Please note that the sources covered by this permit are required to meet all emission limits and conditions contained in the permit at all times, including during the initial operation period.
(b) Reevaluating BACT: The permittee shall submit information for reevaluating BACT to the Department at least 18 months prior to the commencement of construction of any permitted processes that may have not begun construction within eighteen months from the date of the issuance of the final permit. [ss. 285.60(1)(a)2 and 285.66(1), Wis. Stats.; s. NR 406.12, Wis. Adm. Code]

(3) Completion of Operation Permit Application :

(a) Compliance information required to complete the operation permit application for the emission units included in this permit should be tted to the DNR at least 4 months prior to the expiration of the Construction Permit.

(b) Operation of the source(s) covered by this permit after this permit expires is prohibited unless a complete operating permit application source(s) has been submitted to the Department.

[s. 285.60(1)(b)1., Wis. Stats.; s. NR 407.04(1)(b), Wis. Adm. Code]

(3) This permit supersedes permit #02-RV-054. [s. 285.65(3), Wis. Stats.]

NN. OTHER CONDITIONS APPLICABLE TO THE ENTIRE FACILITY	
Condition Type: 2. Malfunction Prevention and Abatement Plans	
a. Conditions:	**b. Compliance Demonstration:**
(1) A malfunction prevention and abatement plan shall be prepared and followed for the plant. [s. NR 439.11, Wis. Adm. Code] (2) A written copy of the plan shall be kept at the plant and shall be updated once every five years. [s. NR 439.11(1), Wis. Adm. Code] (3) All air pollution control equipment shall be operated and maintained in conformance with good engineering practices (i.e. operated and maintained according to manufacturer's specifications and directions) to minimize the possibility for the exceedance of any emission limitations [s. NR 439.11(4), Wis. Adm. Code]	(1) The plan shall be developed to prevent, detect and correct malfunctions or equipment failures which may cause any applicable emissions limitation to be violated or which may cause air pollution. [s. NR 439.11(1), Wis. Adm. Code] (2) This plan shall include installation, maintenance and routine calibration procedures for the control equipment instrumentation. This plan shall require an instrumentation calibration at the frequency specified by the manufacturer but not less than once per year plus an inspection and/or calibration whenever instrumentation anomalies are noted. [ss. NR 407.09(1)(c)1.c., NR 439.055(4) and s. NR 439.11, Wis. Adm. Code] (3) The plan shall require a copy of the operation and maintenance manual for the control equipment be maintained on site. The plan shall contain all of the elements in s. NR 439.11(1)(a) - (h), Wis. Adm. Code. [s. NR 439.11, Wis. Adm. Code] (4) The facility shall maintain an inventory of normal consumable items necessary to ensure operation of the control device(s) in conformance with the manufacturer's specifications and recommendations. [s. NR 439.11, Wis. Adm. Code] (5) The facility shall maintain records of the instrumentation calibrations. [s. NR 439.04, Wis. Adm. Code]

NN. OTHER CONDITIONS APPLICABLE TO THE ENTIRE FACILITY
Condition Type: 3. Stack Testing Requirements
a. Conditions:
(1) All testing shall be performed with the emissions unit operating at capacity or as close to capacity as practicable and in accordance with approved procedures. If operation at capacity is not feasible, the source shall operate at a capacity level, which is approved by the Department in writing. [s. NR 439.07(1), Wis. Adm. Code] (2) If the testing for the sources is not completed in the time frame identified in this permit then the permittee shall request an extension upto 60 days to complete the testing. [s. 285.65(3), Wis. Stats.] (2) The Department shall be informed at least 20 working days prior to any stack testing so a Department representative can witness the testing. At the time of notification a compliance emission test plan shall also be submitted to the Department for approval. When approved in writing, an equivalent test method may be substituted for the reference test method. [s. NR 439.07(2), Wis. Adm. Code] (3) Two copies of the report on the tests shall be submitted to the Department for evaluation within 60 days following the tests. [s. NR 439.07(9), Wis. Adm. Code]

NN. OTHER CONDITIONS APPLICABLE TO THE ENTIRE FACILITY

Condition Type: 4. Acid Rain Requirements

a. Conditions:

(1) The permittee shall obtain and secure allowances equal to the actual annual SO2 emissions. (Allowances are available through the Chicago Board of Trade and other sources) [40 CFR Parts 72 and 75, s. NR 409.06(3), Wis. Adm. Code]

(2) The permittee shall have a Designated Representative (DR) in accordance with 40 CFR Part 72. The DR shall be responsible for submitting required permits, compliance plans and emission monitoring reports, allowance plans and compliance certifications; and will be the responsible official with regards to all matters under the acid rain program. [40 CFR Part 72 and 75, s. NR 409.07, Wis. Adm. Code]

(3) The permittee shall submit a Phase II acid rain permit to the Department at least 24 months before the date on which the unit commences operation. [s. 285.65(3), Wis. Stats., s. NR 409.08(1), Wis. Adm. Code]

(4) The owner or operator of a Phase I and phase II acid rain units shall install, calibrate, operate and maintain all monitoring equipment necessary for continuously monitoring sulfur dioxide, nitrogen oxides, carbon dioxide, stack flow rate and opacity. The type of monitoring equipment used and the manner and location of its installation are subject to prior department approval. [s. NR 439.095(1), Wis. Adm. Code]

(5) The owner or operator of monitoring equipment installed to comply with condition I.NN.4.a.(4) shall install, calibrate, maintain and operate the continuous emission monitor in accordance with the performance specifications in 40 CFR part 60, Appendix B or, for affected units, the performance specifications in 40 CFR part 75, Appendices A to I, incorporated by reference in s. NR 484.04(21) and (27), and the requirements in s. NR 439.09. The owner or operator of the source shall submit a quality control and quality assurance plan for approval by the department. The monitor shall follow the plan, as approved by the department. [s. NR 439.095(6), Wis. Adm. Code]

NN. OTHER CONDITIONS APPLICABLE TO THE ENTIRE FACILITY	
Condition Type: 5. Compliance Reports / Records	
a. Conditions:	**b. Compliance Demonstration:**
(1) Upon issuance of the operation permit, the permittee shall submit periodic monitoring reports. [s. NR 407.09(1)(c)3., Wis. Adm. Code] (2) Upon issuance of the operation permit, the permittee shall submit periodic certification of compliance. [s. NR 407.09(4)(a)3., Wis. Adm. Code] (3) The records required under this permit shall be retained for at least five(5) years and shall be made available to department personnel upon request during normal business hours. [s. NR 439.04, s. NR 439.05, Wis. Adm. Code]	(1) Submit a monitoring report, which contains the results of monitoring or a summary of monitoring results required by this permit to the Department every 6 months. (a) The time periods to be addressed by the submittal are January 1 to June 30 and July 1 to December 31. (b) The report shall be submitted to the Wisconsin Department of Natural Resources, Southeast Region, 2300 North Dr. Martin Luther King Jr. Drive, Milwaukee, WI 53212, Phone (414) 263-8500 within 30 days after the end of each reporting period. (c) All deviations from and violations of applicable requirements shall be clearly identified in the submittal. (d) Each submittal shall be certified by a responsible official as to the truth, accuracy and completeness of the report. (e) The content of the submittal is described in item D. of Part II of the operation permit. [s. NR 439.03(1)(b), Wis. Adm. Code] [s. NR 439.03(1)(b), Wis. Adm. Code] (2) Submit an annual, certification of compliance with the requirements of this permit to the Wisconsin Department of Natural Resources, Southeast Region, 2300 North Dr. Martin Luther King Jr. Drive, Milwaukee, WI 53212, Phone (414) 263-8500 and to Compliance Data - Wisconsin, Air and Radiation Division, U.S. EPA, 77 W. Jackson, Chicago, IL 60604]. (a) The time period to be addressed by the report is the January 1 to December 31 period which precedes the report. (b) The report shall be submitted to the Wisconsin Department of Natural Resources, Southeast Region, 2300 North Dr. Martin Luther King Jr. Drive, Milwaukee, WI 53212, Phone (414) 263-8500 and U.S. EPA within 30 days after the end of each reporting period. (c) The information included in the report shall comply with the requirements of Part II Section N of this permit. (d) Each report shall be certified by a responsible official as to the truth, accuracy and completeness of the report. [s. NR 439.03(1)(c), Wis. Adm. Code]

NN. OTHER CONDITIONS APPLICABLE TO THE ENTIRE FACILITY
Condition Type: 6. Acquisition of Emission offsets
a. Conditions:
(1) The permittee shall obtain Volatile Organic Compound offsets at a minimum ration or 1.3 or a total of 294 credit. [s. NR 408.06(4)(d), Wis. Adm. Code] (2) The permittee will ensure that the actual transfer of credits has taken place prior to commencing operation of the power plant. [s. NR 405.06, Wis. Adm. Code] (2) The permittee shall provide information on whether actual transfer of credits has occurred prior to commencing operation of the ERGS's project to the DNR, Bureau of Air Management, 101 S. Webster Street, P.O. Box 7921, Madison, WI 53707. [s. 285.65(3), Wis. Stats., s. NR 408.06, Wis. Adm. Code]

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Mesaba Energy Project

APPLICATION TO THE MINNESOTA POLLUTION CONTROL AGENCY FOR A NEW SOURCE REVIEW CONSTRUCTION AUTHORIZATION PERMIT

MESABA ONE AND MESABA TWO

Prepared by

EXCELSIOR ENERGY

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GLOSSARY OF TERMS AND ACRONYMS

acfm	Actual Cubic Feet per Minute
AERA	Air Emission Risk Analysis
AGR	Acid Gas Recovery
AP-42	USEPA Compendium of Air Pollutant Emission Factors
AQRV	Air Quality Related Values
ASU	Air Separation Unit
BACT	Best Available Control Technology
BFD	Block Flow Diagram
BFW	Boiler Feed Water
BMP	Best Management Practices
Btu	British Thermal Unit
CAA	Clean Air Act
$CaCO_3$	Calcium Carbonate (Limestone)
CAIR	Clean Air Interstate Rule
CaO	Calcium Oxide (Lime)
CCPI	Clean Coal Power Initiative
CE	Cliffs-Erie, LLC
CEMS	Continuous Emission Monitoring System
C.F.R.	Code of Federal Regulations
CE	Cliffs Erie
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COC	Cycles of Concentration
COS	Carbonyl Sulfide
CR/CRs	Country Road(s)
CTG	Combustion Turbine Generator
DLN	Dry Low NO_x
DOE	Department of Energy
DOT	Department of Transportation
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EPRI	Electric Power Research Institute
EU	Emission Unit
FAV	Final Acute Value
FEED	Front End Engineering and Design
FGD	Flue Gas Desulfurization
FSQ	Full Slurry Quench
GCP	Good Combustion Practice

GLG	Great Lakes Gas Transmission Company
GO	Generator Outlet
GPM	Gallons per Minute
gpm	Gallons per Minute
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid
HAP	Hazardous Air Pollutant
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
HVTL	High Voltage Transmission Line
IGCC	Integrated Gasification Combined Cycle
K_2O	Dipotassium Oxide
kW	Kilowatt
LAER	Lowest Achievable Emission Rate
lb/million Btu	Pound per Million British Thermal Unit
lb/MMBtu	Pound per Million British Thermal Unit
LLC	Limited Liability Company
MAAQS	Minnesota Ambient Air Quality Standards
MACT	Maximum Available Control Technology
MDEA	Methyl-Diethanolamine
MDNR	Minnesota Department of Natural Resources
MMBtu	Million British Thermal Units
MMBtu/hr	Million British Thermal Units Per Hour
MOPS	Minnesota Office of Pipeline Safety
MP	Minnesota Power (Company)
MPCA	Minnesota Pollution Control Agency
MW	Megawatt
N_2	Nitrogen
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory (DOE)
NH_3	Ammonia
NiO	Nickel Monoxide
NNG	Northern Natural Gas Co.
NO_X	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NSP	Xcel Energy (Formerly NSP, Northern States Power)
NSPS	New Source Performance Standards

NTP	Notice to Proceed
O&M	Operation and Maintenance
O_2	Oxygen
OSHA	Occupational Safety and Health Administration
PC	Pulverized Coal
PEP	Project Execution Plan
PM	Particulate Matter
PM_{10}	Particulate Matter having an aerodynamic diameter less than 10 Microns
PPA	Power Purchase Agreement
ppmvd	Parts per Million (dry volume)
ppmw	Part per Million (wet basis)
PRB	Powder River Basin
PSD	Preventive of Significant Deterioration
psig	Pounds per Square Inch (gauge)
PSQ	Partial Slurry Quench
PTE	Potential to Emit
RACT	Reasonable Available Control Technology
RCRA	Resource Conservation and Recovery Act
S	Sulfur
SO_3	Sulfur Trioxide
scf	Standard Cubic Feet
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
SIL	Significant Impact Limits
SNCR	Selective Non Catalytic Reduction
SO_2	Sulfur Dioxide
SRU	Sulfur Recovery Unit
STG	Steam Turbine Generator
SV	Stack Vent
Syngas	Synthetic Gas
TCLP	Toxicity Characteristic Leaching Procedure
TDS	Total Dissolved Solids
TiO_2	Titanium Dioxide
TOC	Total Organic Carbon
TP	Total Phosphorous
TPY	Tons Per Year
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulate Matter
TSS	Total Suspended Solids
TTRA	Taconite Tax Relief Area

VOC	Volatile Organic Compounds
WWTF	Waste Water Treatment Facility
ZLD	Zero Liquid Discharge

1. INTRODUCTION

1.1 Applicant and Air Emission Facility to be Permitted

Excelsior Energy Inc. ("Excelsior"), an energy development company based in Minnetonka, Minnesota has created two wholly-owned project companies, MEP-I LLC and MEP-II LLC (MEP-I LLC and MEP-II LLC, together, the "Applicant" or "Company") to construct, own and operate at a site in Northeastern Minnesota a 1,212 megawatt$_{(net)}$ integrated gasification combined cycle ("IGCC") steam electric power generating station (hereafter, the "IGCC Power Station") fueled by coal and other solid, petroleum-based feedstocks. The Company hereby makes application for a Part 70/New Source Review Construction Authorization for the IGCC Power Station pursuant to the major source provisions of the State of Minnesota's New Source Review ("NSR") program (otherwise referred to as the Prevention of Significant Deterioration ["PSD"] program). Provisions codified at Minn. R. 7007.0200 and 7007.0150, subp.1, and 40 C.F.R. § 52.21 outline the informational requirements for such applications, the assembly of which information is collectively provided herein and hereafter referred to as the "Application").

1.2 Contents of Application

As required, the Application contains relevant applicant information (below in this Section 1), a description of the proposed air emission facility (Section 2), a discussion of regulatory applicability (Section 3), emission estimates (Section 4), determination of Best Available Control Technology (Section 5), a description of the land on which the IGCC Power Station is to be located and the existing meteorology and background air quality characterizing the area (Section 6), an Air Quality Impact Assessment (Section 7), an analysis of impacts to Air Quality Related Values (Section 8), and application forms (Section 9). Table 9.0-1 provided at the beginning of Section 9 provides a summary of the forms included and is intended to facilitate review of the Application.

Calculations used in developing all emission estimates are provided in Appendix A (for criteria pollutants) and Appendix B (for hazardous air pollutants). Appendices C and D contain support for the ambient air quality source impact analysis presented in Section 7 and Section 8. Finally, The Applicant has sponsored preparation of an Air Emission Risk Analysis ("AERA") in accordance with procedures contained in the Minnesota Pollution Control Agency's ("MPCA") AERA Guide (see http://www.pca.state.mn.us/air/aera-guide.html). The report confirming the findings of the AERA is attached as Appendix E.

1.3 Mesaba Energy Project: Phase I and II

The IGCC Power Station described herein consists of Phase I and Phase II of the Mesaba Energy Project (hereafter, "Mesaba One and Mesaba Two," respectively) each phase of which is nominally rated at peak to deliver 606 megawatts ("MW_{net}") of electricity to the bus bar of the high voltage switchyard located within the IGCC Power Station's fenced boundary.

1.4 Terminology

In the following sections of the Application the terms “Project” or “Mesaba One” will be used synonymously with the phrases “Phase I IGCC Power Station” and “Phase I Development.” The term “Mesaba Two” will be used synonymously with the phrases “Phase II IGCC Power Station” and “Phase II Development.” The combined Phase I and Phase II Developments will be used synonymously with the term “Mesaba One and Mesaba Two” and the phrase “Phase I and II IGCC Power Station.” The phrases “IGCC Power Station”, “Power Station”, or “Station” will be used where the context with respect to Mesaba One, Mesaba Two, or both, is obvious. The term “IGCC Power Station Footprint” or “Station Footprint” means the fenced area within which the IGCC Power Station is located. “Buffer Land” means the land area contiguous with or adjacent to the IGCC Power Station Footprint, extending to the boundary of the property controlled by the Applicant and upon which limited Station-related activity occurs. The term “Associated Facilities” means the buildings, equipment, and other physical structures that are necessary to operate the Station and includes, without limitation: the equipment identified in Sections 1.6.5, 1.6.6, and 1.6.7.

1.5 Applicant Information

The Applicant’s offices are located at 11100 Wayzata Boulevard, Suite 305, Minnetonka, Minnesota 55305. The contact for the Application is:

Mr. Robert S. Evans II
Vice President, Environmental Affairs
Telephone: (952) 847-2355
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Email Address: BobEvans@excelsiorenergy.com

1.6 Overview of Phase I and II Developments

1.6.1 Location

Mesaba One and Mesaba Two will be located in the Taconite Tax Relief Area (“TTRA”) of Northeastern Minnesota in conformance with Minnesota Statutes §216B.1694. Figure 1.6-1 shows the boundary of the TTRA and the location of the IGCC Power Station. A general location map is provided in Figure1.6-2 and shows the IGCC Power Station’s proximity to Voyageur’s National Park (“VNP”), the Boundary Waters Canoe Area Wilderness (“BWCA”), and Rainbow Lake Wilderness Area, the closest Class 1 areas. A map showing the IGCC Power Station Footprint, Buffer Land, and the Station’s immediate proximity to significant receptors is provided in Figure 1.6-3.

Figure 1.6-1 Minnesota Taconite Tax Relief Area

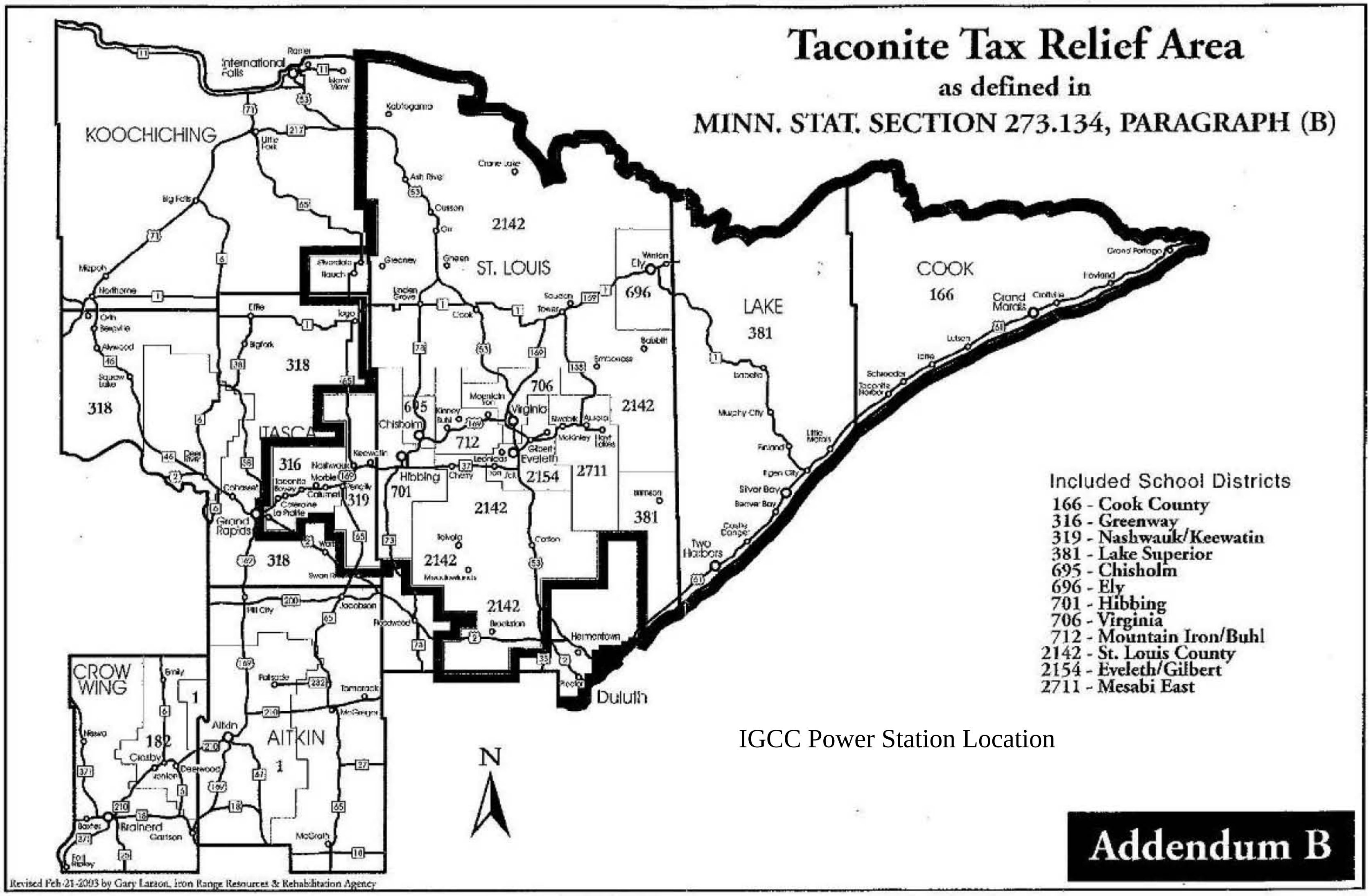


Figure 1.6-2 IGCC Power Station Regional Vicinity Map

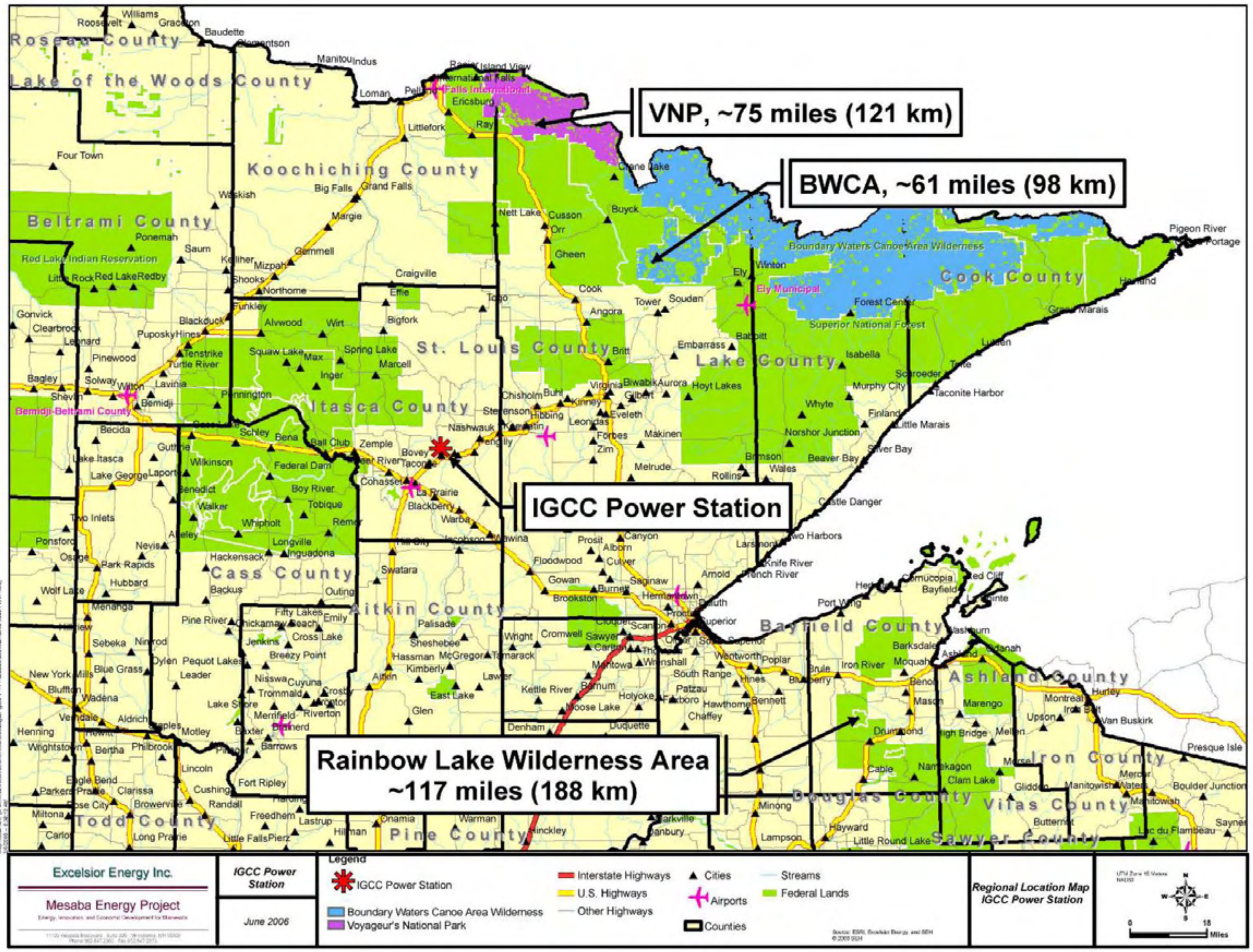
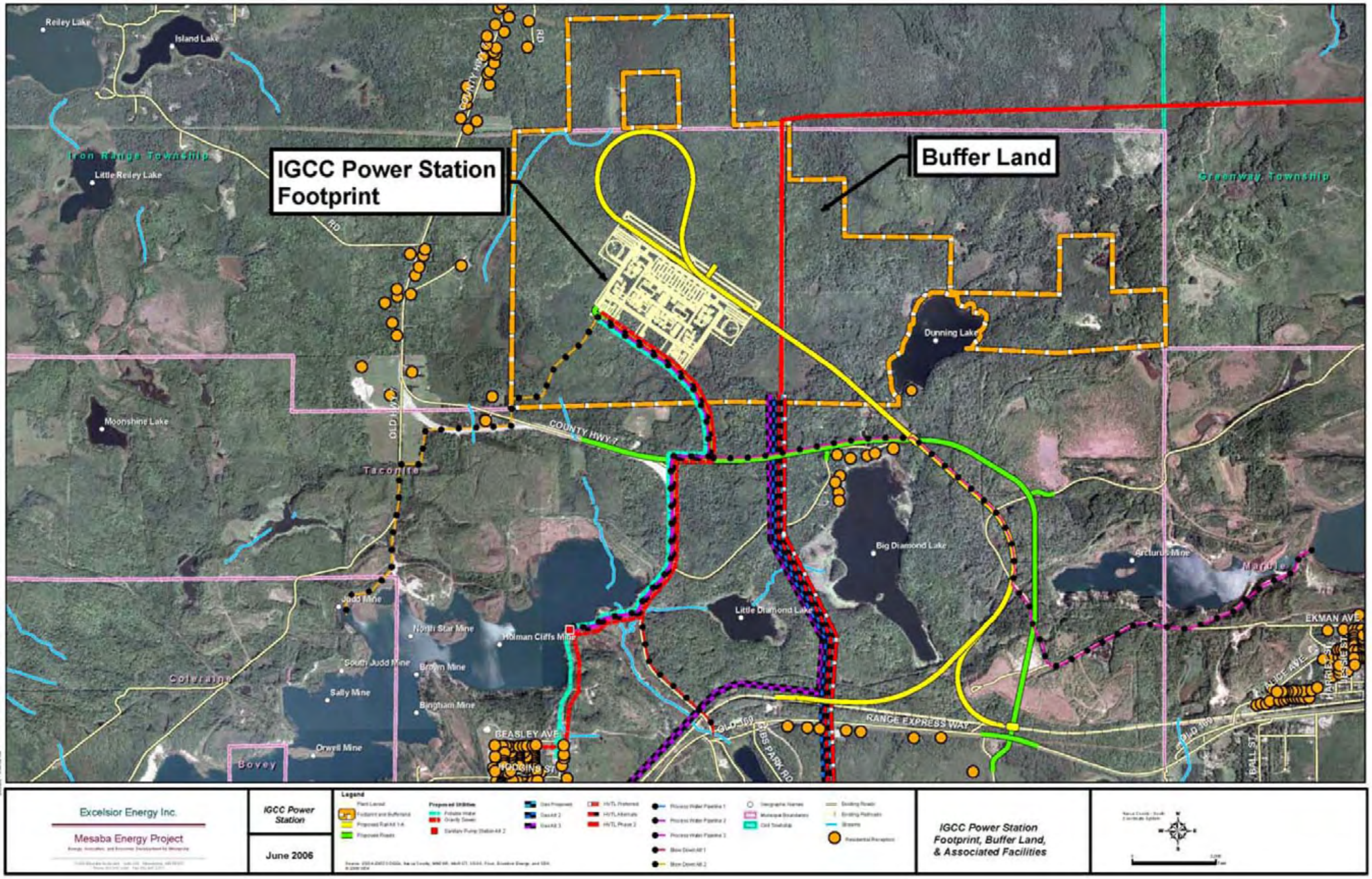


Figure 1.6-3 Phase I and II IGCC Power Station Footprint, Buffer Land and Proximity to Significant Receptors



In general, the Site is currently undeveloped and unoccupied but is located in the immediate vicinity of former iron ore mining operations and in immediate proximity to critical infrastructure, including water resources, transportation corridors, mine access roads, transmission corridors, major substations, and community resources. The IGCC Power Station Footprint and Buffer Land is located completely within Iron Range Township (4th Principal Meridian, T56N, R24W) and is generally bounded by County Road 7 to the west and south, a high voltage transmission line corridor to the north, and the Township boundary to the east. As shown in Figure 1.6-3, all but about 200 acres of the property identified as Buffer Land is located within the city limits of Taconite, Minnesota.

1.6.2 Description of IGCC Technology

The gasification process the Applicant will use to supply fuel to its combined cycle power station is ConocoPhillips E-Gas™ technology. In the E-Gas™ process, coal, petroleum coke, or blends of coal and petroleum coke are crushed, slurried with water, and pumped into a pressurized vessel (the gasifier) along with sub-stoichiometric amounts of purified oxygen. In the gasifier, controlled reactions take place, thermally converting feedstock materials into a gaseous fuel known as synthesis gas, or syngas. The syngas is cooled, cleaned of contaminants, and then combusted in a combustion turbine, which is directly connected to an electric generator. The assembly of the combustion turbine and generator is known as a combustion turbine generator (“CTG”). The expansion of hot combustion gases inside the combustion turbine creates rotational energy that spins the generator and produces electricity. The hot exhaust gases exiting the CTG pass through a heat recovery steam generator (“HRSG”), a type of boiler, where steam is produced. The resulting steam is piped to a steam turbine that is connected to an electric generator. The expansion of steam inside the steam turbine spins the generator to produce an additional source of electricity. When a CTG and a steam turbine generator (“STG”) are operated in tandem at one location to produce electricity in a highly efficient manner the combination of equipment is referred to as a combined cycle electric power plant. Integration of the gasification process with the combined cycle power plant is known as integrated gasification combined cycle technology, or IGCC, an inherently lower polluting technology to produce electricity from solid feedstocks.

1.6.3 Maximum Emission/Discharge Scenarios Quantified

During the environmental review and permitting process, the Applicant is required to identify operating scenarios producing maximum emissions/discharges associated with construction and operation of the IGCC Power Station. Such scenarios are primarily defined by the operating characteristics of Station equipment and the amounts and characteristics of feedstock to be transported, handled and consumed. Maximum quantities of feedstock consumed and feedstock characteristics are further discussed in Section 2.

For development of its “worst case” scenario, the Applicant focused on identifying operating parameters yielding maximum emissions. In general, these scenarios reflect the highest heat input rates and a cautious approach regarding the design optimizations expected to occur (during the Front End Engineering and Design [“FEED”] process, the preliminary equipment designs used to estimate environmental releases will be refined and uncertainties that now require conservatively high assumptions to be used will be better understood allowing such conservative assumptions to be refined). In employing such an approach, the Applicant is confident that environmental releases and their associated impacts are conservatively analyzed and presented.

Operating conditions producing maximum emissions/discharges from the IGCC Power Station are identified in Section 2 and assume operation of the gasifiers under partial slurry quench ("PSQ") conditions and consider known seasonal influences and the range of potential feedstocks for which the IGCC Power Station will be designed to utilize. Information is also presented to describe the gasifier operating in full slurry quench ("FSQ") mode. FSQ is achieved by increasing the slurry feed to the second stage of the gasifier to the point where only slurry is used to quench the syngas, thereby eliminating the thermal loss associated with water used to cool the syngas and increasing the overall efficiency of the IGCC Power Station. These efficiency gains will translate into reduced feedstock use and, consequently, reduced pollutant emissions/discharges. However, FSQ is an IGCC Power Station design improvement that is subject to further engineering and verification. Therefore, FSQ's expected benefits are shown, but not reflected in either the maximum resource requirements or maximum pollutant emissions/discharges quantified in the Application.

1.6.4 Feedstock Flexible

The Applicant is proposing to construct and operate Mesaba One and Mesaba Two as feedstock flexible Power Stations that can interchangeably use the following feedstocks:

- 100% bituminous coal (including, but not limited to, Illinois No. 6 bituminous coal)
- 100% subbituminous coal (including, but not limited to, Powder River Basin coal)
- Up to a 50:50 coal/petroleum coke blend
- Other blends of these feedstocks

Natural gas will be used to start up the IGCC Power Station and as a backup fuel when syngas is unavailable. The maximum natural gas flow is expected to be about 105 million standard cubic feet of gas per day per phase of the IGCC Power Station.

1.6.5 IGCC Power Station Footprint and Buffer Land

The Applicant has secured an option on 1260 acres of property within the boundary of the Buffer Land shown in Figure.1.6-3. The actual physical space required for the Mesaba One Footprint encompasses approximately 100 acres. An additional 80 acres of land is required for a temporary construction laydown area for Mesaba One and five acres for a concrete batch plant. Figure 1.6-4 shows the layout plan for Mesaba One and many of its Associated Facilities. The equipment layout for Mesaba Two and its Associated Facilities will be similar to Mesaba One. Therefore, about 200 acres will be required for Mesaba One and Mesaba Two, excluding construction and laydown areas. The remainder of the Buffer Land is required for security, isolation and unspecified future requirements.

The detailed site layout plan for Mesaba One and Mesaba Two is shown in Figure 1.6-5. The location of the most significant point sources of air pollutant emissions are identified in Figure 1.6-5 with the symbol "   ". The dimensions of significant buildings/structures inside the battery limits ("ISBL") of the IGCC Power Station have been tabulated and placed adjacent to the left margin in Figure 1.6-5.

Figure 1.6-6 provides a preliminary site grading plan designed to minimize impacts on wetlands and an outline of the earth work required to accommodate the Phase I and II Developments. Ambient air quality modeling studies detailed later in Sections 7.0 and 8.0 take into account the base elevations shown in this figure. The reference lines provided in Figure 1.6-6 correspond to the cross-sections illustrated in Figure 1.6-7.

Visualizations of the Phase I and Phase I and II Developments are shown in Figures 1.6-8 and 1.6-9, respectively.

1.7 Implementation Schedule

The proposed IGCC Power Station would be constructed in two phases. Electric power for each project phase would be produced in two CTGs (about 220 $MW_{(gross)}$ each) and in a STG (up to 300 $MW_{(gross)}$). Power generated from the project would be interconnected to the regional electrical grid by a high voltage transmission line ("HVTL") system. The Project milestone schedule is provided in Figure 1.7-1. The Applicant proposes to commence construction of Mesaba One in the first quarter of 2008 and begin commercial service in the fourth quarter of 2011. The commercial in service date for Phase II is scheduled for 2013 with construction commencing in 2010.

Figure 1.6-4. Preliminary Equipment Layout Plan for Mesaba One

Figure 1.6-5. Preliminary Layout Plan for Mesaba One and Mesaba Two Showing Point Sources of Air Emissions and Building Heights

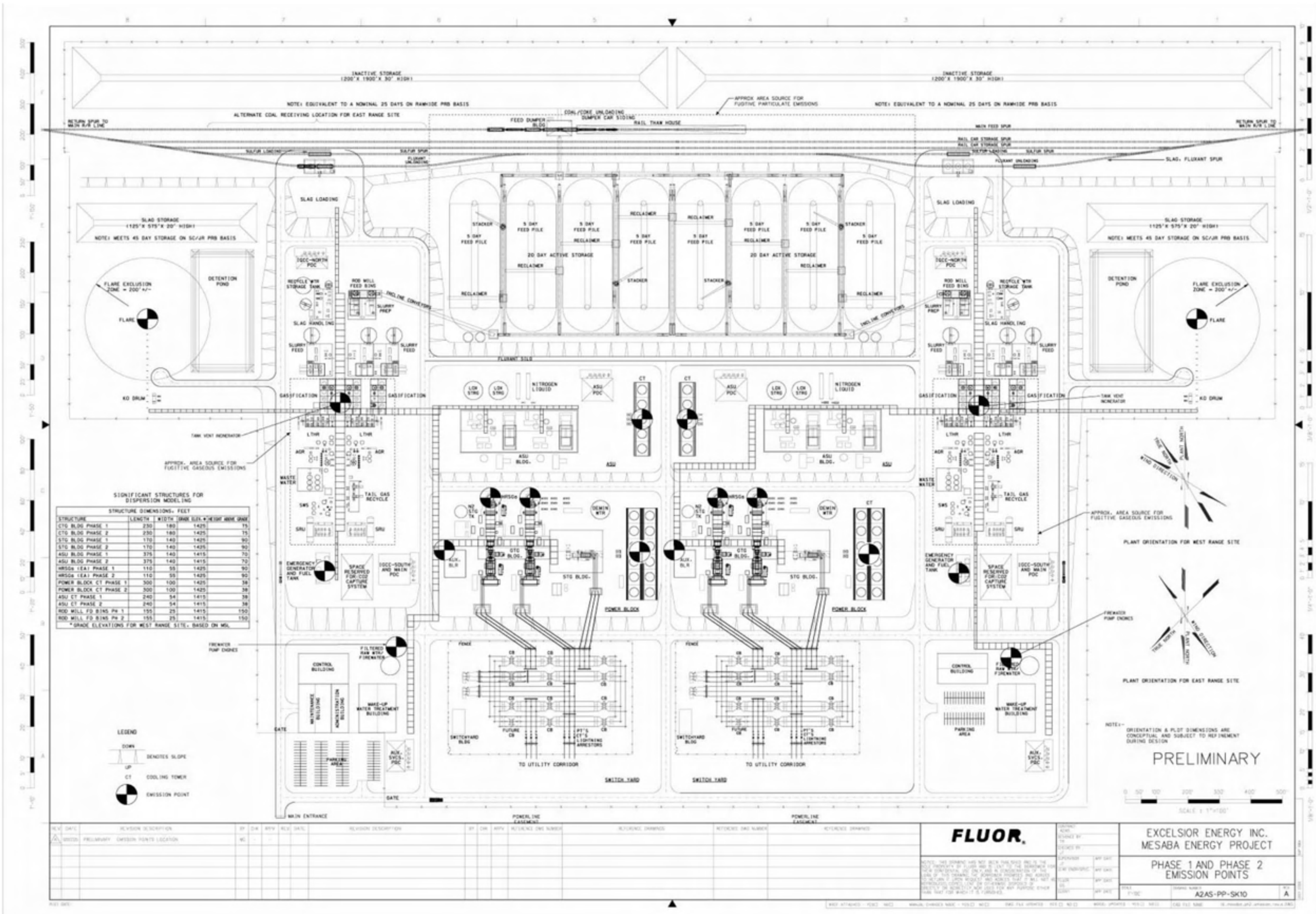


Figure 1.6-6. Preliminary Grading Plan for Mesaba One and Mesaba Two

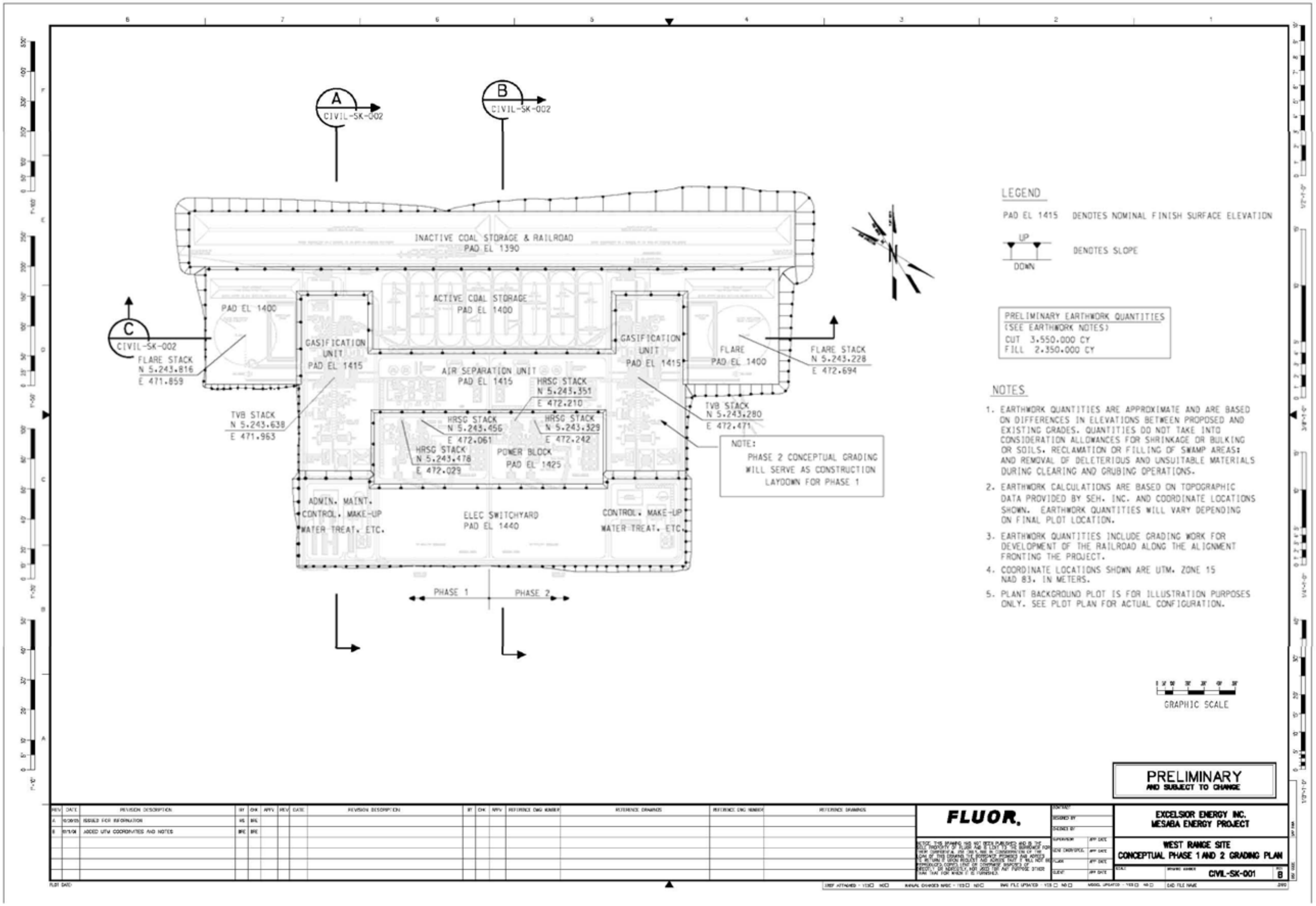


Figure 1.6-7 Cross Sections of Phase I and II IGCC Power Station Footprint

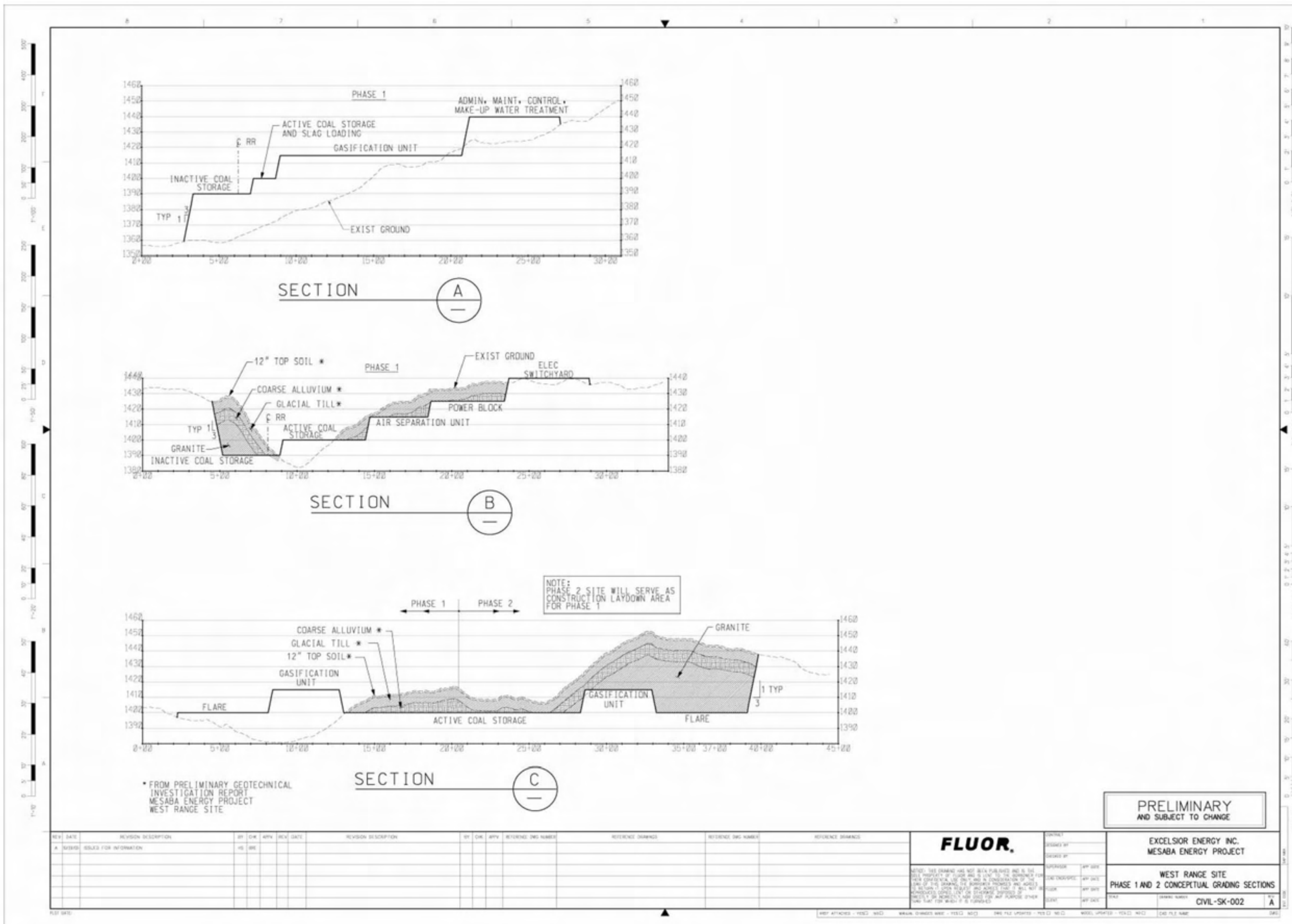


Figure 1.6-8. Visual Rendering of Mesaba One

Figure 1.6-9. Artist's Rendering of Mesaba One and Mesaba Two

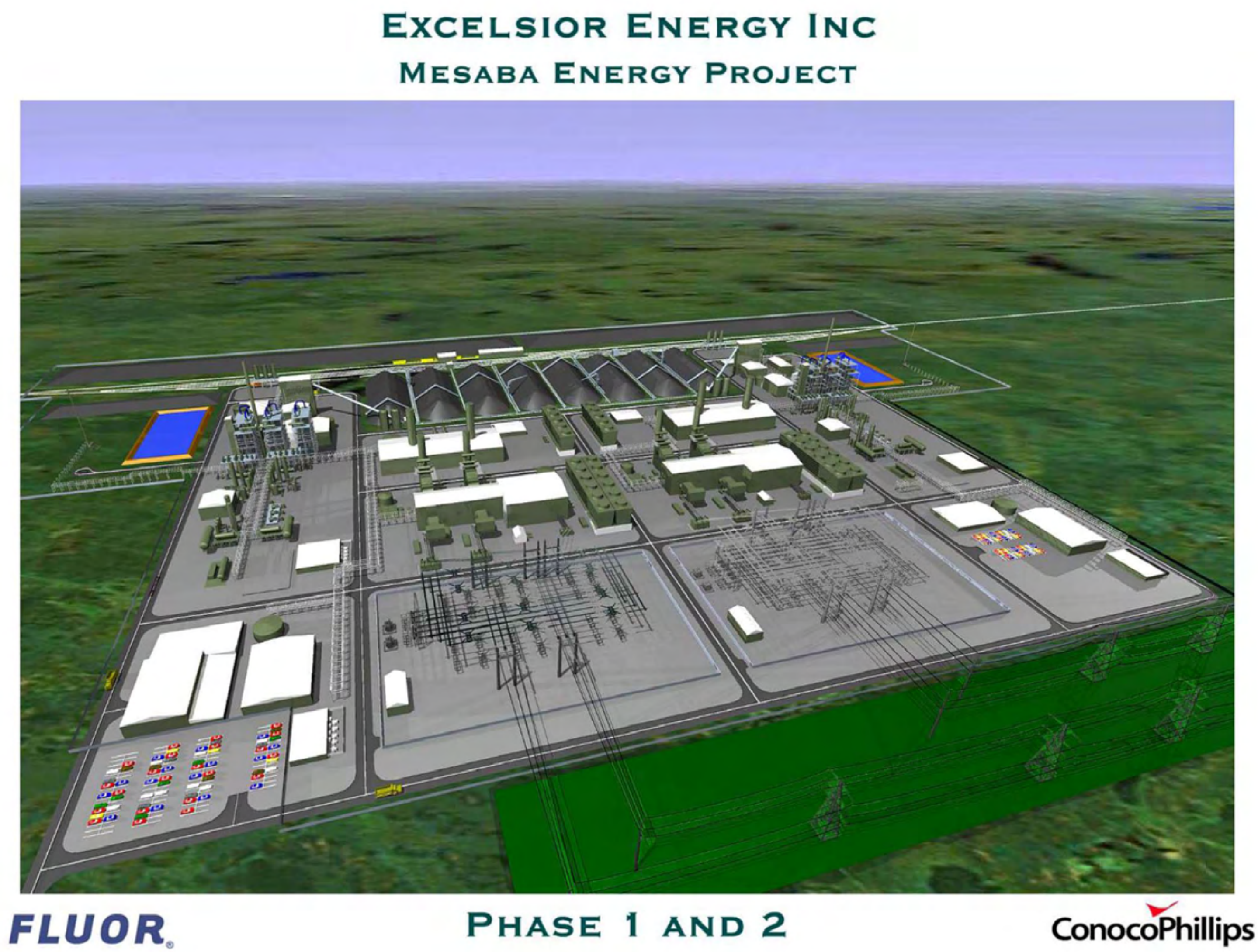


Figure 1.7-1. Mesaba One and Mesaba Two Implementation Schedule

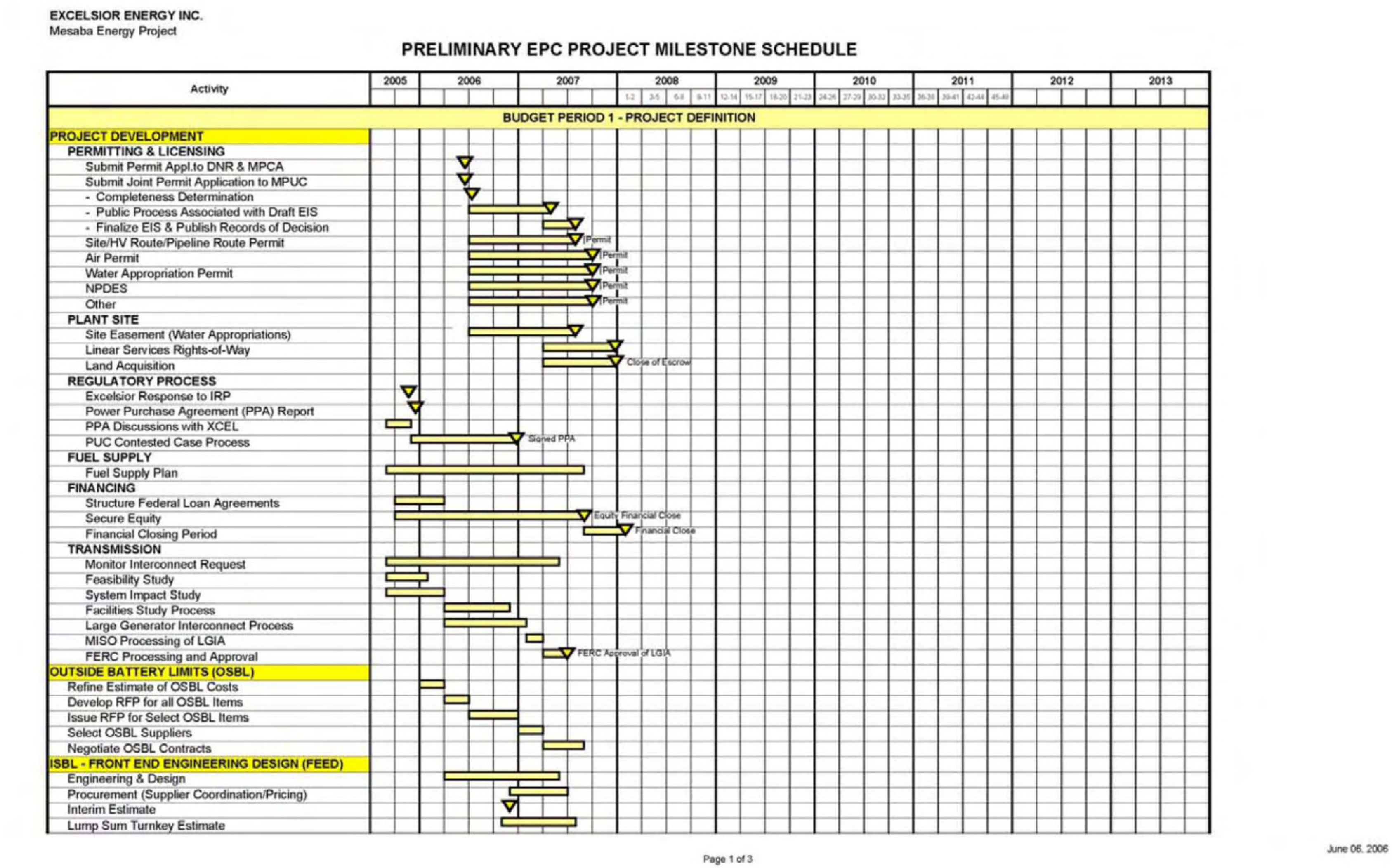


Figure 1.7-1. Mesaba One and Mesaba Two Implementation Schedule (Continued)

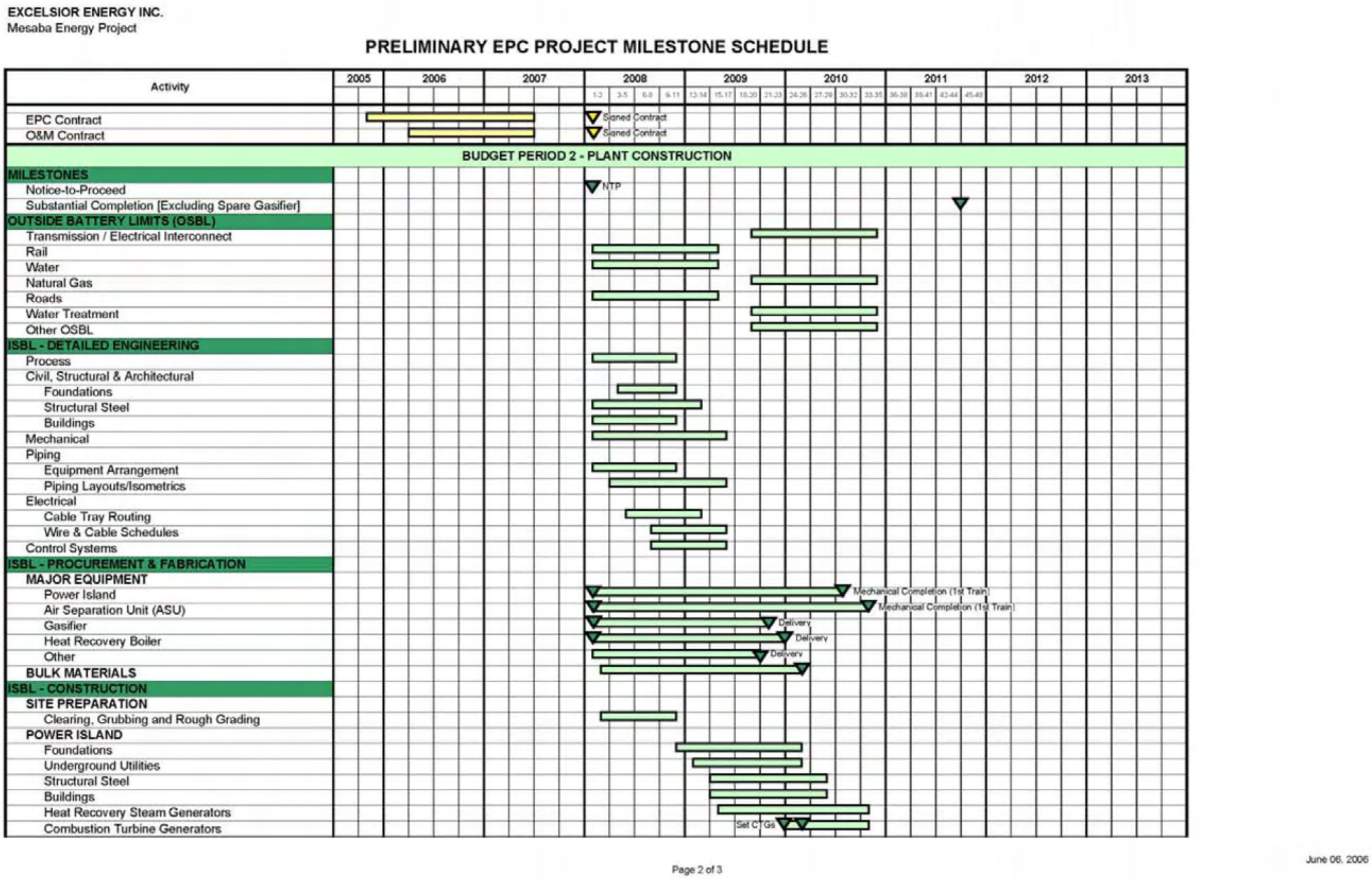
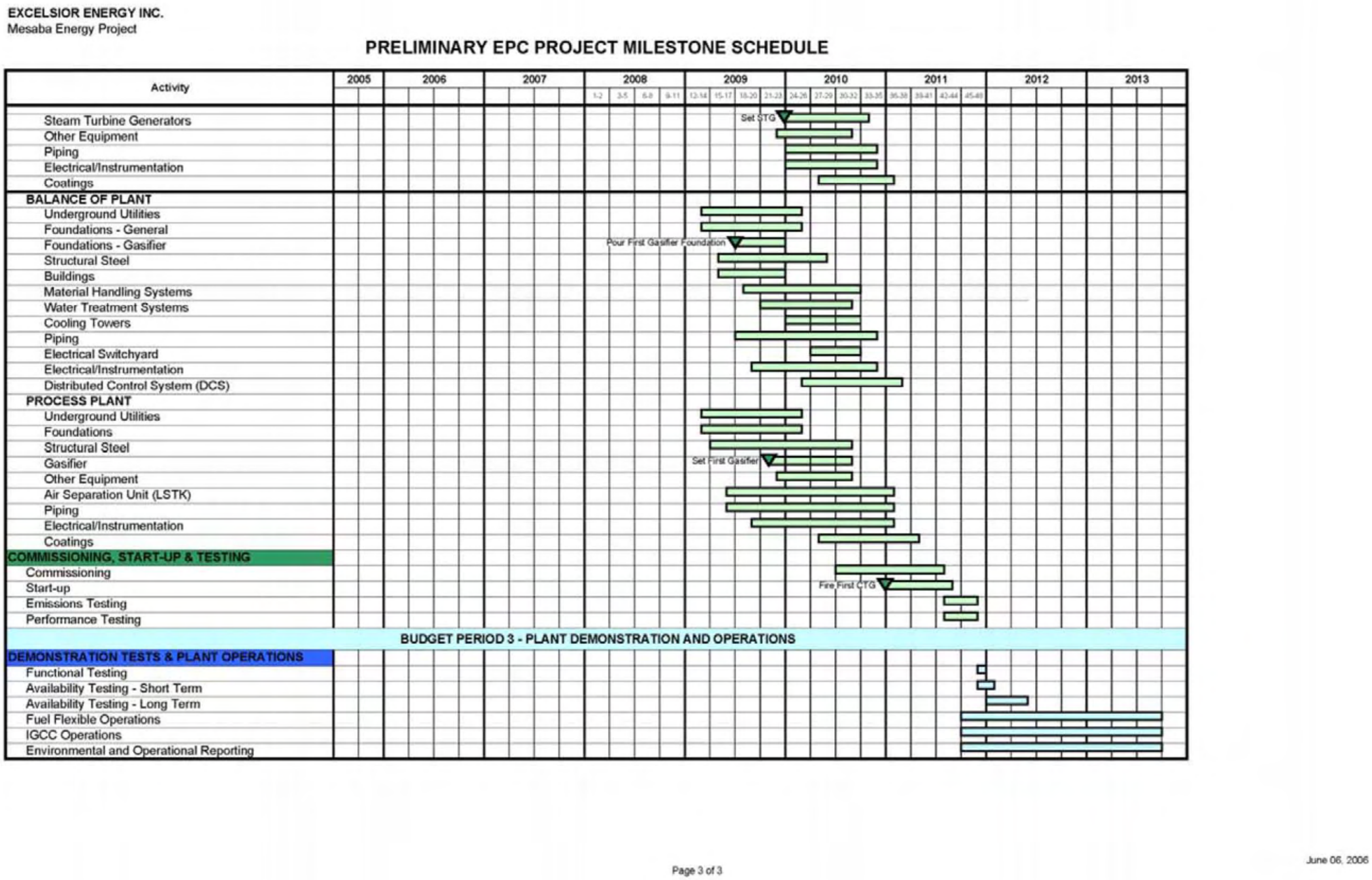


Figure 1.7-1. Mesaba One and Mesaba Two Implementation Schedule (Continued)



2. PROJECT DESCRIPTION

2.1 Resource Inputs

2.1.1 Feedstock Delivery

Coal and petroleum coke feedstocks will normally be received by rail in dedicated unit trains from the mine or refinery. Rail access into the IGCC Power Station Footprint is from existing BNSF Railway ("BNSF") and Canadian National Railway ("CN") tracks. The rail loop will be designed to accommodate unit trains up to 135 cars in length within the Site boundary with the average unit train shipment comprised of 115 cars. Each unit train car will carry on average about 119 tons of feedstock (BNSF, 2005).

Each phase of the IGCC Power Station, under the maximum feedstock input case and assuming the gasifiers are operating in full slurry quench ("FSQ") mode would require a maximum of 8,230 tons of coal per day on an as-received basis. If operating in a partial slurry quench ("PSQ") mode, the daily maximum required fuel tonnage would increase to 8,550 tons on an as-received basis.

One 135-car unit train could deliver 16,100 tons of coal and each 115 car unit train about 13,700 tons. With Mesaba One and Mesaba Two operating at full load with the gasifiers in FSQ mode, a maximum 16,460 tons of coal feedstock per day would be consumed, requiring the delivery of about five 115 car unit trains every four days. With the gasifiers operating in PSQ mode, Mesaba One and Mesaba Two would require under full load operations a maximum of about 17,100 tons of coal per day. Such operating mode would not substantively change the worst case, short term fuel delivery schedule. A maximum of four hours will be typically be required to unload one unit train. The Applicant estimates that a maximum of three unit trains per day (midnight to midnight) could be received and unloaded.

Mesaba One would utilize a maximum of 3.12 million tons of feedstock annually assuming operation in PSQ mode at 100 percent capacity factor. The Applicant expects to operate in FSQ mode most of the time and expects to take outages for maintenance each year. Assuming a 90% capacity factor and operation in the FSQ mode, the Applicant would expect to use a maximum of 2.7 million tons of feedstock per year. The Applicant seeks a permit which reflects the maximum fuel consumption case. Because of the plant's fuel flexible capability, it is anticipated that specific fuel utilization will change periodically throughout the lifetime of the IGCC Power Station, with selection based upon the conditions and terms available from various fuel and transportation suppliers.

The location selected for Mesaba One and Mesaba Two offers two major coal transport alternatives, the BNSF and CN, each having direct access to the IGCC Power Station Footprint by construction of short spurs. The availability of multiple rail transportation modes at the site will enhance the long-term benefits of the feedstock-flexible plant design. This capability introduces potential competition into the fuel supply equation and should result in lower fuel costs over the life of the IGCC Power Station.

2.1.2 Feedstock Receiving and Storage

The feedstock handling system will include facilities necessary to unload solid feedstock materials, convey them to storage areas, store until required, reclaim them from storage, blend as necessary, and convey the blended materials to the slurry preparation system. On-site storage facilities will be provided for two feedstock materials, coal and petroleum coke. Storage facilities will also be provided for flux, a feedstock conditioning material. The feedstock storage facilities will include, for each phase of the facility, approximately 20 days of active storage and approximately 25 days of inactive storage. The storage areas will incorporate dust suppression systems (including covered conveyers and other enclosures, dust suppression sprays, and vent filters) and will be paved, lined, or otherwise controlled to enable collection and treatment of storm water runoff and to prevent infiltration to ground water of chemical species leached from feedstock materials and/or flux.

Unloading facilities will include a thawing shed to loosen frozen cargo during the winter season, and a partially enclosed rotary car dumping system. After the locomotive on a unit train positions the first car in the rotary dumper, subsequent cars are placed in the dumping position by an automatic electro-hydraulic positioner. Such rail car positioning systems reduce the run time and fuel consumption of the locomotives or switch engines and the emissions that would otherwise occur if all engines were required to run during the entire unloading process (this normally allows all but one engine to be shut down; the engine remaining is operated at a reduced load to maintain air pressure in the brakes). Feedstock materials fall from the rotated cars into an enclosed pit from which such materials are transferred via a feeder/conveyor system to active storage pile stackers. Four active storage piles for each phase of the facility will provide working feedstock storage. Additional inactive storage will be located on the opposite side of the rail sidings to provide a reserve source of feedstock material in the event normal deliveries of unit trains are interrupted. If needed, feedstock from the inactive pile will be moved by mobile equipment (bulldozers, scrapers, and/or front-end loaders) to the rail unloading pit to access the automated plant feed system. Reclaimers and conveyors will move coal and petroleum coke from the active piles to the slurry feed preparation area.

2.1.3 Feedstock and Feedstock Characteristics

Mesaba One and Mesaba Two are designed to be “feedstock flexible” throughout their economic lifetimes. While conventional pulverized coal (“PC”) fired power plants can sometimes use a limited range of fuels, they must be designed for a specific performance fuel. When using other fuels, the performance and output of these PC plants typically deteriorate. Feedstock flexibility will allow the IGCC Power Station to operate at or near maximum capacity using:

- 100% bituminous coal (for example, Illinois No. 6 coal), or
- 100% sub-bituminous coal (for example, Power River Basin coal), or
- Up to a 50:50 coal/petroleum coke blend, or
- Other blends of these fuels.

This feedstock flexibility, made possible by the use of IGCC technology and the design parameters for Mesaba One and Mesaba Two, will provide ongoing future cost benefits because it allows the Station to adapt its feedstock mix over the life of the facility to minimize the cost of power. Feedstock flexibility provides Mesaba One and Mesaba Two a hedge against physical dependency upon a single feedstock supplier or transportation provider, and against supply disruptions from any mine or carrier. Table 2.1-1 shows the feedstock design specifications being utilized to design the Station's unique feedstock flexibility.

Table 2.1-1
Feedstock Design Specification Basis

FEEDSTOCK	BITUMINOUS COAL		SUB-BITUMINOUS COAL		PETROLEUM COKE	
	DRY BASIS	AS RCVD.	DRY BASIS	AS RCVD.	DRY BASIS	AS RCVD.
HHV, Btu/lb	12,802	11,586	11,942	8,300	15,204	13,699
Ultimate Analysis, Wt %						
Carbon	70.79	64.06	69.9	48.58	87.32	78.71
Hydrogen	4.81	4.35	4.8	3.34	3.67	3.31
Nitrogen	1.51	1.37	0.9	0.63	1.31	1.18
Sulfur	3.32	3.00	0.53	0.37	6.27	5.65
Oxygen	6.92	6.26	16.77	11.66	0.72	0.65
Chlorine	0.14	0.13	<0.01	<0.01	0.01	0.01
Ash	12.51	11.32	7.1	4.93	0.7	0.63
Total	100.00	90.50	100.0	69.50	100.00	90.10
Moisture, %		9.5		30.5		9.9
Ash Mineral Analysis, Wt%						
SiO_2	49.57	NA	31.2	NA	20.55	NA
Al_2O_3	19.32	NA	13.9	NA	9.11	NA
TiO_2	0.96	NA	1.1	NA	0.8	NA
Fe_2O_3	19.32	NA	6.3	NA	5.44	NA
CaO	3.81	NA	24.3	NA	11.77	NA
MgO	1.01	NA	6.1	NA	3.64	NA
Na_2O	0.46	NA	1.7	NA	1.68	NA
K_2O	2.40	NA	0.2	NA	0.66	NA
P_2O_5	0.35	NA	0.5	NA	0.52	NA
SO_3	2.07	NA	13.6	NA	23.75	NA
NiO	NA	NA	NA	NA	4.68	NA
V_20_5	NA	NA	NA	NA	16.11	NA
Other	0.73	NA	1.1	NA	1.29	NA
Total	100.0		100.0		100.0	
Ash Fusion Temp. (Reducing), ^oF						
Initial Deformation	2000	NA	2170	NA	2440	NA
Softening (H=W)	2150	NA	2180	NA	2500	NA
Hemispherical (H=1/2w)	2185	NA	2190	NA	2555	NA
Fluid	2370	NA	2200	NA	2600	NA
Hardgrove Grindability Index	50-65	NA	80	NA	53	NA

Although the primary fuel source for electric power production will be syngas produced from the feedstocks specified above, the IGCC Power Station will also be capable of operating on pipeline natural gas. The power island is a combined-cycle unit, optimized for operation on syngas. The ability to operate on natural gas provides an additional source of available generating capacity (and reliability for periods when the gasification island is unavailable). The capability of the combined cycle equipment to operate on natural gas offers the option of installing the combined-cycle power island early in the construction process (ahead of the gasification section), thereby allowing for electricity production from natural gas until the gasification section is installed and the IGCC Power Station begins full-time, base load operation on coal-derived syngas. Early operation of the combined cycle power island in this manner is not currently planned. However, in the event of an unforeseen regional contingency, the combined cycle equipment could be started and operated, thereby representing a very useful resource planning option. The Applicant is requesting herein permits for Mesaba One and Mesaba Two to allow for natural gas firing at capacity factors of 30%, 20%, 10% and 5% for years 1, 2, 3, and thereafter, respectively. In addition, the Applicant is requesting a permit to combust natural gas at 100% load in the event of catastrophic occurrence to the gasifiers.

2.1.4 Flux Receiving and Storage

The E-Gas™ gasifier will operate at high temperatures. At such temperatures, ash in feedstock material will melt and drain to the bottom of the gasifier where it is removed. The molten ash – known as slag – will be cooled and solidified in a water bath outside the gasifier.

Mineral matter in the ash determines the temperature at which ash in the gasifier will melt and the slag viscosity at a specific operating temperature. If the slag is too viscous, it will not flow easily from the gasifier, or could plug the bottom. Flux, typically silica/sand, limestone, iron oxide (or iron ore), or a mixture of these, will be blended with the feed as necessary to control the slag melting point and fluidity. A slag that is too fluid could be excessively erosive to the refractory in the gasifier, so the amount and composition of flux, if used, must be carefully monitored and controlled.

Flux will normally be received by truck (or railcar) and pneumatically conveyed to enclosed storage silos equipped with fabric filters for dust control. Flux from storage silos will be automatically blended with feedstock by a weigh belt feeder system. The required quantity of flux will be a small fraction of the total feed, typically less than 250 tons per day per phase.

The feedstock and flux handling/storage facilities and their associated emission controls are further reviewed in Section 4.1.5 in order to predict fugitive particulate matter emissions attending operation of the IGCC Power Station.

2.1.5 Natural Gas Supply Pipeline and Metering Station

Natural gas will be used to start up the facility and as a backup fuel (see Section 4.1.1). When operating on natural gas, the power block of the Phase I IGCC Power Station cannot achieve the nominal 606 MW(net) output attainable as when operating on syngas. This is due, in part, to the lack of nitrogen that would otherwise be available for nitrogen dilution and power augmentation from operation of the ASU system used primarily to supply oxygen to the gasifiers. The maximum natural gas utilization by the IGCC Power Station is predicted to be about 105 million standard cubic feet of gas per day per phase.

Natural gas will be supplied through a direct connection with the Great Lakes Gas Transmission Company ("GLG") pipeline located about 12 miles due south of the IGCC Power Station or from Northern Natural Gas company's ("NNG") tapping point located in La Prairie, Minnesota, about 10 miles west-southwest of the Station. This access to multiple pipeline infrastructure alternatives is beneficial. The Proponent will contract with either or both entities for natural gas transportation capacity for quantities and at pressures sufficient to operate the IGCC Power Station at its limited capability (see above paragraph) when firing its backup fuel. The Applicant will purchase natural gas through a series of contracts with gas suppliers in order to obtain the lowest overall fuel price and best contract conditions for this commodity. The Applicant will install and operate metering equipment to monitor purchases. Typical natural gas composition is shown in Table 2.1-2.

Table 2.1-2
Typical Natural Gas Constituents

CONSTITUENT	PERCENT BY VOLUME
Methane	96.9
Ethane	2.00
Propane	0.50
n-Butane	0.10
i-Butane	0.10
n-Pentane	0.00
i-Pentane	0.00
Hexane+	0.10
Oxygen	0.00
Carbon dioxide	0.00
Nitrogen	0.30
TOTAL	**100.00**
Sulfur, ppmv	14.8
Specific Gravity (air = 1.00)	0.57-58
Net Heating Value (Btu per scf)	935

Btu = British thermal units.
scf = standard cubic feet.

2.1.6 Cooling Water and Cooling Tower Blowdown (Black & Veatch, 1996)

Heat must be rejected from the IGCC Power Station's condensers in order to maintain proper steam cycle characteristics. A large volume of water is required for this purpose (a 600 MW pulverized coal power plant would require about 300,000 gallons of water per minute for a once-through cooling system). The IGCC Power Station will use cooling towers to reduce relative to a once-through cooling system the amount of water otherwise required to be withdrawn from source waters. In a cooling tower, warmed cooling water from the Power Station's condenser will be cooled by the evaporation of a portion of the water as it passes through the cooling tower. In addition to evaporation, a small amount of entrained water, called drift (water droplets that are entrained in the exhaust air stream carrying heat away from the towers), will be emitted to the external environment. As evaporation continues, salts dissolved in the remaining cooling water become more concentrated. When the concentrations of dissolved salts near their solubility limit, scale formation may occur on the plant's condenser tubes and hinder heat transfer.

Although addition of certain chemicals can inhibit scale formation, a portion of the cooling water, called blowdown, must be discharged. The amount of blowdown is calculated as follows:

$$\text{Blowdown} = \frac{\text{Evaporation}}{\text{Cycles - 1}} - \text{Drift}$$

The cycles, or "cycles of concentration," relate to how much the dissolved solids are allowed to concentrate in the cooling water system. Assuming: i) the Power Station is operating on eight cycles of concentration; ii) the total amount of water recirculated in the power block and gasification/ASU cooling towers is approximately 320,000 gallons per minute; iii) drift constitutes approximately 0.001% of the water being recirculated; iv) the plant operates at a 92% capacity factor; and v) the concentration of mercury in the raw make-up water is 0.9 nanograms per liter; releases of mercury via drift could be expected to be on the order of 0.04 grams per year per phase of the IGCC Power Station. Releases on this order of magnitude are considered to be inconsequential from an environmental perspective.

2.1.7 Contact Process Water

Water is used in numerous enclosed vessels to cool and clean the syngas. This is generally accomplished by routing the syngas through a countercurrent flow of water, with the syngas generally being introduced into the bottom of a tower and water at the top. The water, by virtue of its physical contact with the contaminated syngas, picks up soluble and insoluble contaminants, becomes contaminated itself, and thereafter is treated. In Mesaba One and Mesaba Two, such contact process waters will be segregated from cooling tower blowdown and routed through a ZLD system, thereby ensuring that no trace elements carried over from the feedstock will be discharged to ambient receiving waters. Proprietary systems incorporated into the sour water treatment system remove any mercury from the wastewater stream prior to processing the wastewater stream through the brine concentrator and ZLD system.

2.2 Major Buildings, Infrastructure, Topography, and Access Roadways

The major buildings associated with the IGCC Power Station include the control room, administration building, warehouse/maintenance shop, combustion turbine and steam turbine buildings, weather enclosures for the Air Separation Unit (ASU) compressors, coal slurry preparation, water treatment/lab, railcar thaw shed, switchyard control room, several power distribution centers (prefabricated) and a visitor's center. For purposes of ambient air quality modeling, the dominant structures on site include the following (with approximate dimensions indicated):

- Combustion Turbine Generator Building, 230 ft. x 180 ft. x 75 ft. high.
- Steam Turbine Generator Building, 170 ft. x 140 ft. x 90 ft. high.
- Air Separation Unit (ASU) Building, 375 ft. x 140 ft. x 70 ft. high.
- Heat Recovery Steam Generator (HRSG), 110 ft. x 55 ft. x 90 ft. high.
- Rod Mill Feed Bins, 155 ft. x 25 ft. x 150 ft. high.

These structures and their relative proximities to the IGCC Power Station's point and fugitive emission sources are identified in Figure 1.4-5. A preliminary engineering layout of the IGCC Power Station Footprint and the finished grade elevations currently projected are shown on Figure 1.4-6. The dominant geographic feature on the IGCC Power Station Footprint is a hill that rises approximately 60 feet above the 1,425 foot base elevation at which the IGCC Power Station's HRSGs would be located.

Road access to the IGCC Power Station is currently planned from two directions. Heavy construction traffic, including some construction workers, would access the IGCC Power Station Footprint from U.S. Highway 169, about 1.4 miles east of County Road No. 7. Remaining construction personnel and permanent employees would access the IGCC Power Station Footprint from County Road No. 7. Figure 1.6-3 shows the proposed access roads into the IGCC Power Station Footprint. Current plans call for Itasca County to sponsor construction and operation of this new roadway

2.3 Process Description

Detailed descriptions are provided below for the subsystems within an IGCC Power Station configured to use ConocoPhillips' E-Gas™ technology. The subsystems included are oxygen supply, feedstock slurry preparation, gasification, slag handling, syngas cooling, particulate matter removal, mercury removal, syngas scrubbing, low temperature heat recovery, acid gas removal, sulfur recovery, tank vent collection, sour water treatment and the combined cycle power block. An overall schematic block flow diagram identifying important equipment and processes related to air pollutant emissions from Mesaba One and Mesaba Two are presented in Figures 2.3-1 and 2.3-2. The numbering scheme in Figures 2.3-1 and 2.3-2 is consistent with the numbering scheme provided on the permit application forms in Section 9.

Figure 2.3-1. Block Flow Diagram Showing Air Pollutant Emission Sources for Mesaba One

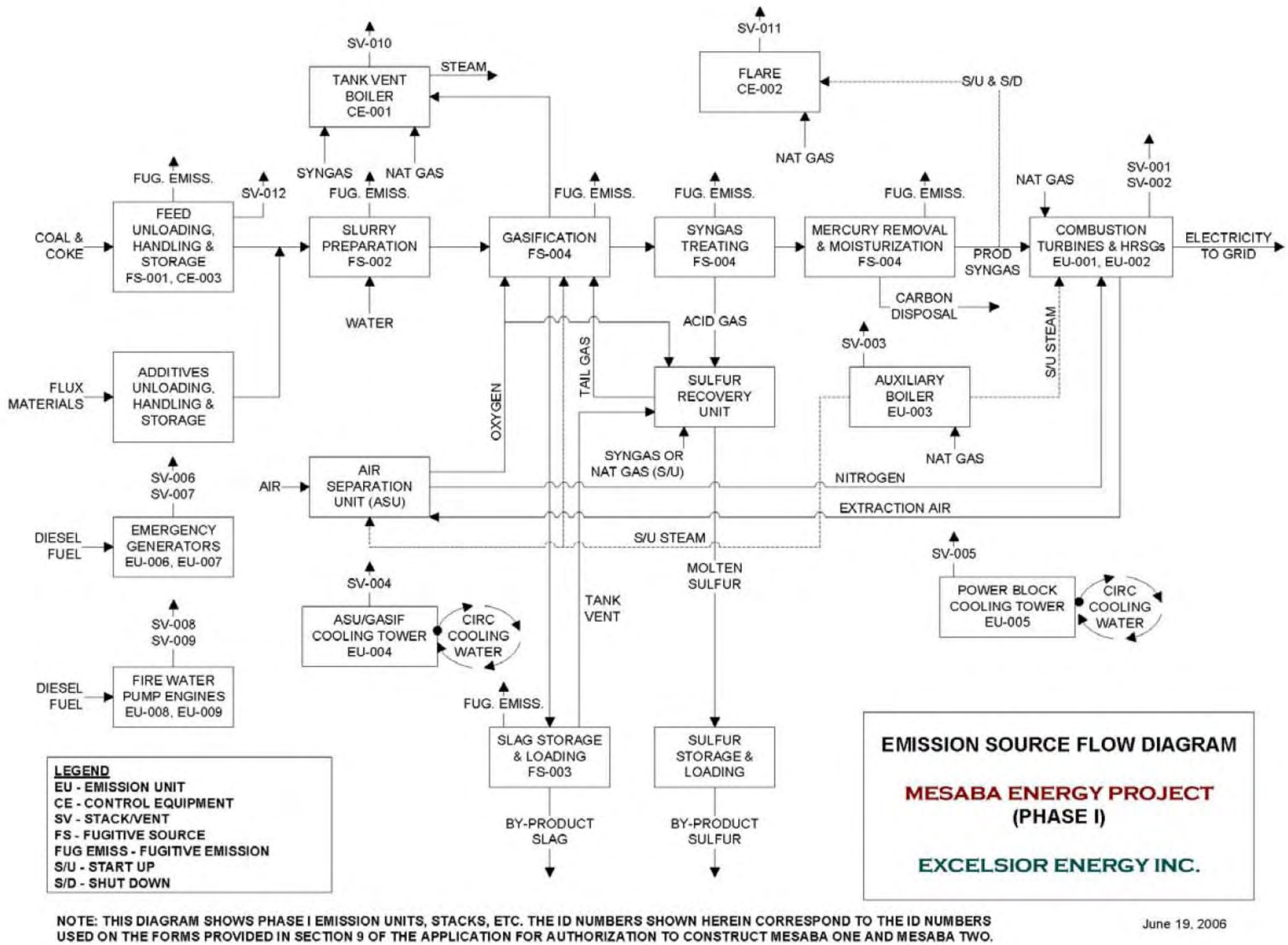
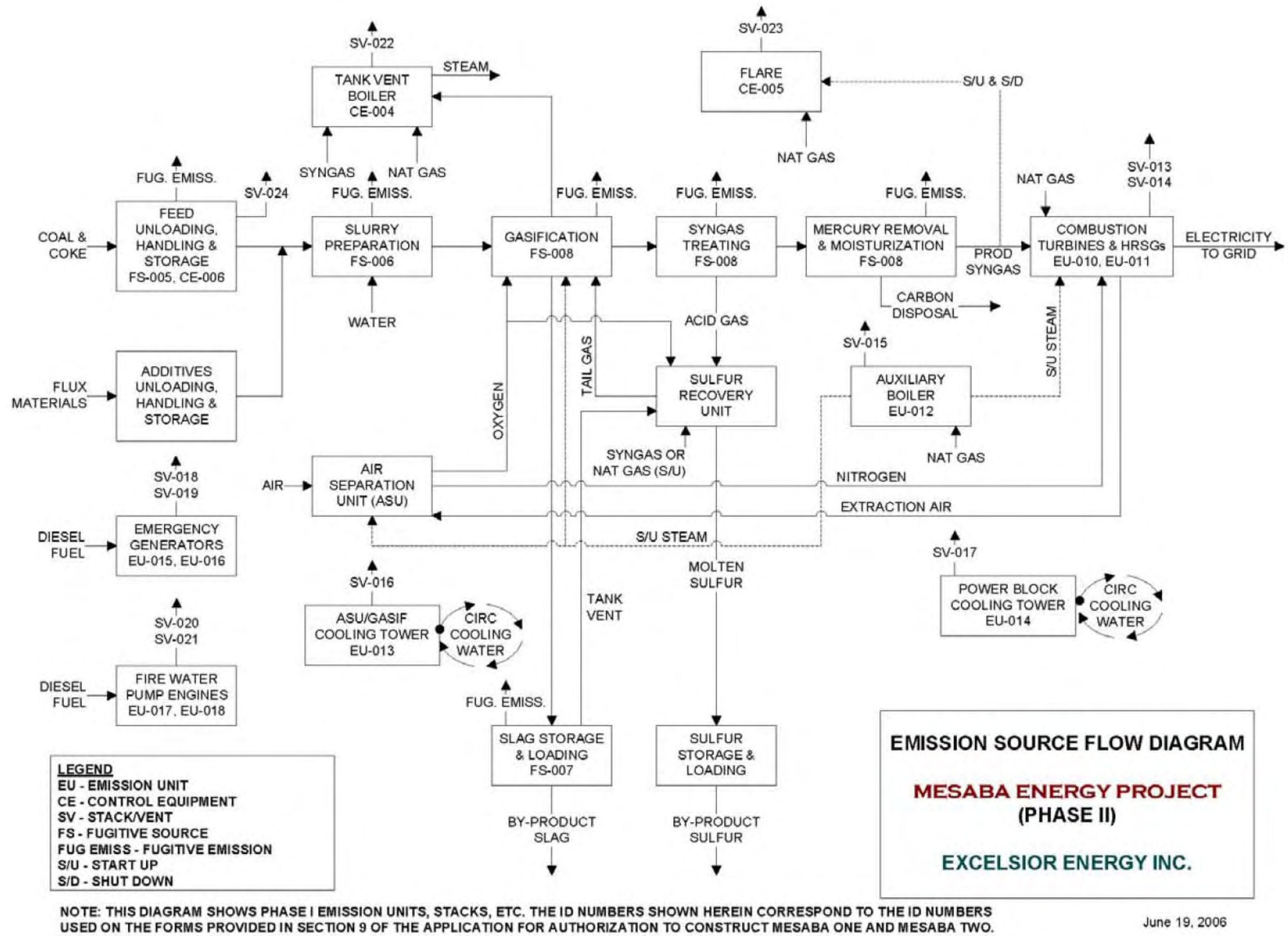


Figure 2.3-2 Block Flow Diagram Showing Air Pollutant Emission Sources for Mesaba Two



2.3.1 Process Chemistry

2.3.1.1 Gasification

Coal and petroleum coke are typically characterized by their heating value, elemental analysis (weight percent carbon, hydrogen, nitrogen and sulfur), mineral matter (also known as ash), and moisture content. Unlike traditional pulverized coal power plants where fuel is actually combusted, in an IGCC power station, coal and/or petroleum coke slurry is fed to the gasifier along with pure oxygen ("O_2"), and a number of complex chemical reactions occur. A portion of the feedstock is partially oxidized to provide the temperatures necessary for gasification. The gasification temperature is high enough to break essentially all the chemical bonds present in the coal and establish a new mix of smaller molecules based on the following primary reactions:

$C + O_2 = CO_2$ (rapid exothermic, or heat releasing, oxidation reaction)

$C + ½ O_2 = CO$ (rapid exothermic oxidation reaction)

$C + H_2O = CO + H_2$ (slower endothermic, or heat consuming, reaction)

$C + CO_2 = 2CO$ (slower endothermic reaction)

$CO + H_2O = H_2 + CO_2$ ("water gas shift reaction", exothermic and rapid)

$CO + 3H_2 = CH_4 + H_2O$ ("methanation reaction", exothermic)

$C + 2H_2 = CH_4$ (direct methanation, exothermic)

Most of the sulfur in the feedstock is converted to hydrogen sulfide ("H_2S") during the gasification process. A small portion of the sulfur is converted into carbonyl sulfide ("COS"). Most of the nitrogen in the feedstock is converted to ammonia ("NH_3"). The syngas composition leaving the gasifier is determined by the gasifier operating temperature and the relative kinetics of the above reactions. Most of the energy in the feedstock is ultimately converted into carbon monoxide ("CO") and hydrogen ("H_2"), and a small amount of methane ("CH_4"). Low grade coals with lower heating values and higher moisture contents will generate a syngas with more CO_2 and H_2, the additional CO_2 generated from the water gas shift reaction shown above. Higher quality coals and petroleum coke will result in a syngas that has a much higher CO content.

2.3.1.2 COS Hydrolysis

Because the small fraction of COS formed in the gasifier is difficult to remove in the Acid Gas Removal ("AGR") system, the COS is "hydrolyzed" in a catalytic reactor before the syngas is sent to the AGR system. The hydrolysis reaction is shown below:

$COS + H_2O = H_2S + CO_2$

The conversion of COS to H_2S is not 100%, and is limited by the equilibrium conditions at the COS reactor operating temperature.

2.3.1.3 Acid Gas Removal

The AGR system uses methyl diethanolamine ("MDEA"), a weak base, to remove the H_2S from the syngas. H_2S is a weak acid that forms weak chemical bonds with the cold lean MDEA solution. Once the MDEA solution absorbs the H_2S, it is called a "rich" solution. The rich MDEA solution is regenerated to a lean MDEA solution by reducing the pressure, applying heat and boiling it. The H_2S released from the rich MDEA under such conditions is sent to the sulfur recovery unit ("SRU").

2.3.1.4 Sulfur Removal

The SRU uses Claus technology to convert H_2S to elemental sulfur. The Claus reactions are shown below:

$$H_2S + \frac{3}{2}O_2 = SO_2 + H_2O$$

$$SO_2 + 2H_2S = 2S + 2\ H_2O$$

The Claus reactions occur in two steps. In the first step a portion of the H_2S is combusted with O_2. The sulfur dioxide ("SO_2") that is formed is mixed with additional H_2S and passed over catalyst beds. The Claus reactions are exothermic and reaction heat is recovered, generating low pressure steam. The "tail gas" stream leaving the Claus reactors contains nitrogen (N_2) and other inert gases that entered with the feeds, along with traces of unconverted H_2S. The tail gas is recycled to the gasifier.

2.4 Process Operations

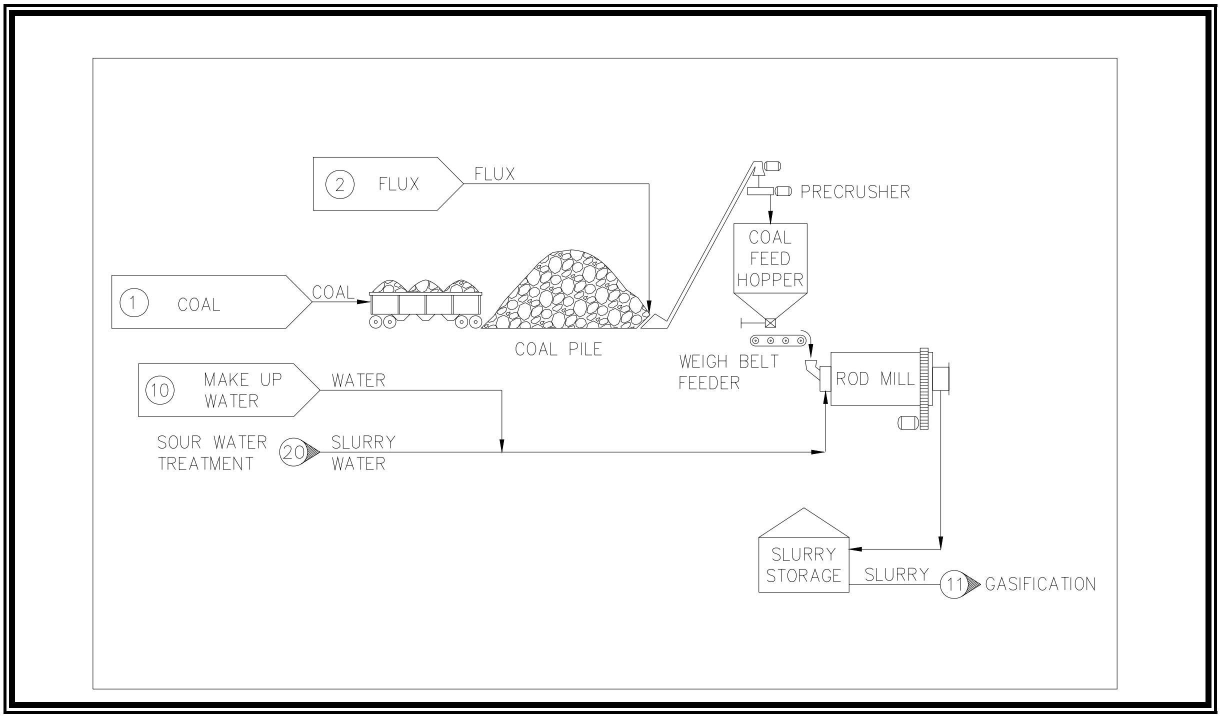
2.4.1 Slurry Preparation

To produce slurry gasifier feed, the solid feedstock is placed on a weigh belt feeder and directed to the rod mill where it is mixed and ground with treated recycled water and slag fines that are recycled from other areas of the gasification island. The resulting slurry has a paste-like consistency. The use of a wet rod mill reduces potential fugitive particulate matter emissions from the grinding operations and is an efficient method for producing essentially homogeneous slurry. Collection and reuse of water within the gasification island minimizes water consumption and discharge.

Slurry feeding allows for consistent and safe introduction of feed into the gasifiers. Prepared slurry will be stored in an agitated tank. The capacity of the slurry storage tank will be sufficiently large to supply the gasifiers' needs without interruption when the rod mill undergoes normal maintenance requirements. The feedstock grinding and slurry preparation area is depicted in Figure 2.4-1-1.

Tanks, drums and other areas of potential atmospheric exposure to the slurry or recycle water will be covered and vented into the tank vent collection system for vapor emission control. The entire feedstock grinding and slurry preparation facility will be paved and curbed to contain spills, leaks, wash down, and storm water runoff. A trench system will carry this water to a sump where it will be pumped into the recycle water storage tank.

Figure 2.4-1. Feedstock Grinding and Slurry Preparation

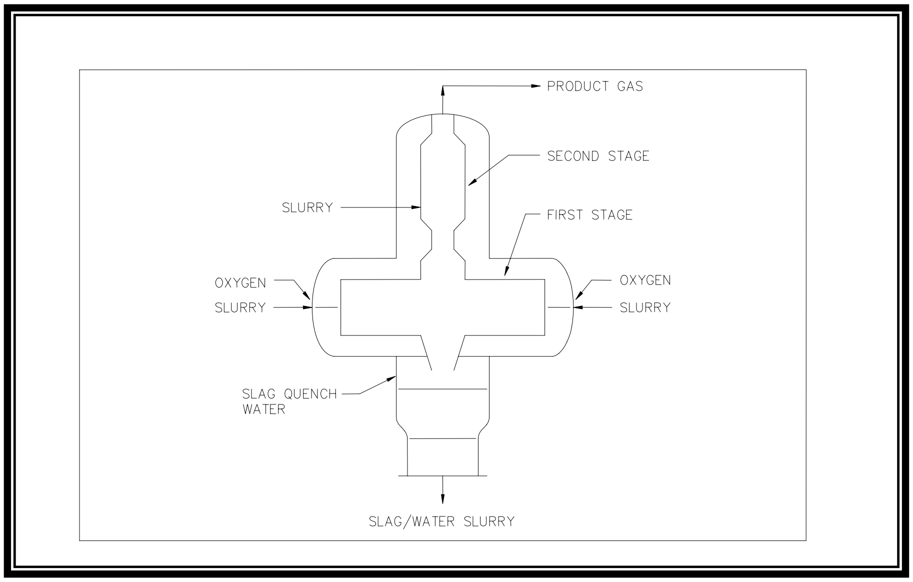


Tanks, drums and other areas of potential atmospheric exposure to the slurry or recycle water will be covered and vented into the tank vent collection system for vapor emission control. The entire feedstock grinding and slurry preparation facility will be paved and curbed to contain spills, leaks, wash down, and storm water runoff. A trench system will carry this water to a sump where it will be pumped into the recycle water storage tank.

2.4.2 Gasification and Slag Handling

The E-Gas™ gasifier consists of two stages: a slagging first stage, and an entrained flow, non-slagging second stage, as depicted in Figure 2.4-2. The first stage is a horizontal refractory-lined vessel in which feedstocks will be exposed to sub-stoichiometric quantities of oxygen at an elevated temperature and pressure. Oxygen and preheated slurry are fed to each of two opposing mixing nozzles, one on each end of the horizontal section of the gasifier. The oxygen feed rate to the nozzles will be carefully controlled to maintain a gasification temperature above the ash fusion point to allow good slag removal and high carbon conversion. The feedstock will be almost totally gasified in this environment to form syngas consisting principally of hydrogen (“H_2”), carbon monoxide (“CO”), carbon dioxide (“CO_2”) and water (“H_2O”).

Figure 2.4-2 E-Gas™ Gasifier



Sulfur in the fuel will be primarily converted to H_2S, with a small portion converted to carbonyl sulfide ("COS"). With the pollutant removal processing system provided downstream, over 99% of the sulfur will be removed from high sulfur feedstocks. Over 97% of the sulfur will be removed from low-sulfur sub-bituminous coal feedstocks. The sulfur removal rate from low sulfur coal results in approximately equal sulfur emissions rates to the higher removal rate from higher sulfur coal. The removal rate from low sulfur coal nonetheless results in approximately equal sulfur emission rates to the higher removal rate from higher sulfur coal. In other words, the final SO_2 emission rate achieved using E-Gas™ technology is independent of the starting sulfur concentration in the feedstock. Therefore the percentage of SO_2 removed from a higher sulfur feedstock that exhibits the same SO_2 emission rate as a lower sulfur feedstock, would show a higher percentage removal rate.

To illustrate, if one assumes the emission rates of Coal A or Coal B equal 0.025 lbs per million Btu heat input, the percentage of SO_2 removed for Coal A and Coal B would be as follows:

% SO_2 removal, Coal A (3.0% S, 11,500 Btu/pound higher heating value):

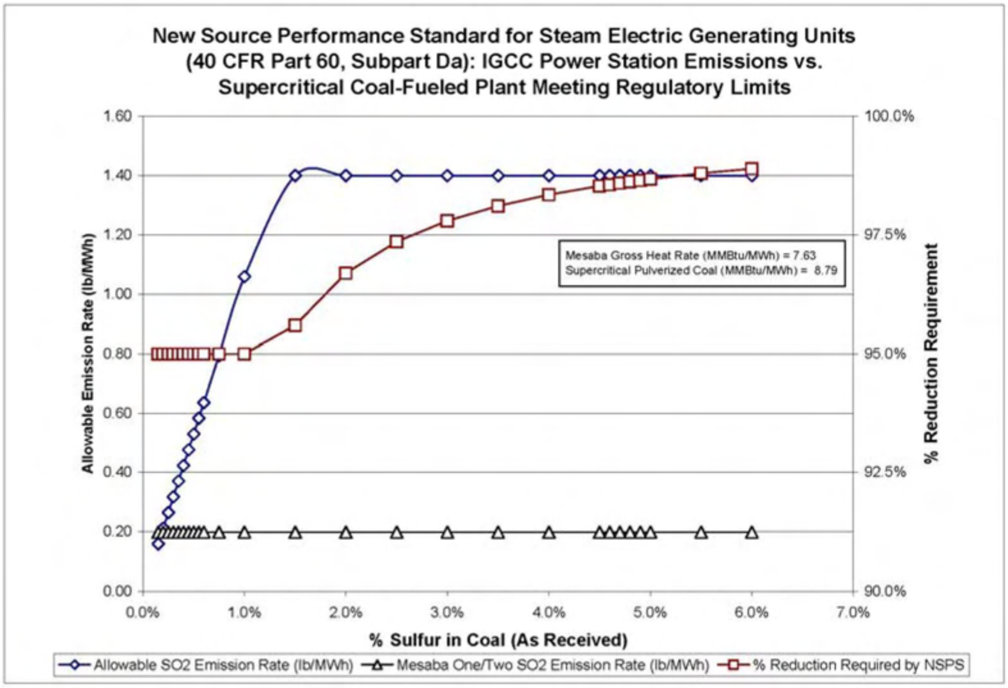
$$\frac{\{[(0.03\text{ lbs S/lb Coal A})*(2\text{ lbs SO2/lb S})*(10^6\text{ Btu/MMBtu})/11{,}500\text{ Btu/lb Coal A}] - 0.025\text{ lb/MMBtu}\}}{[(0.03\text{ lbs S/lb Coal A})*(2\text{ lbs SO2/lb S})*(10^6\text{ Btu/MMBtu})/11{,}500\text{ Btu/lb Coal A}]} \times 100\% = 99.5\%$$

% SO_2 removal, Coal B (0.5% S, 8,300 Btu/pound higher heating value):

$$\frac{\{[(0.005\text{ lbs S/lb Coal B})*(2\text{ lbs SO2/lb S})*(10^6\text{ Btu/MMBtu})/8{,}300\text{ Btu/lb Coal B}] - 0.025\text{ lb/MMBtu}\}}{[(0.005\text{ lbs S/lb Coal B})*(2\text{ lbs SO2/lb S})*(10^6\text{ Btu/MMBtu})/8{,}300\text{ Btu/lb Coal B}]} \times 100\% = 97.9\%$$

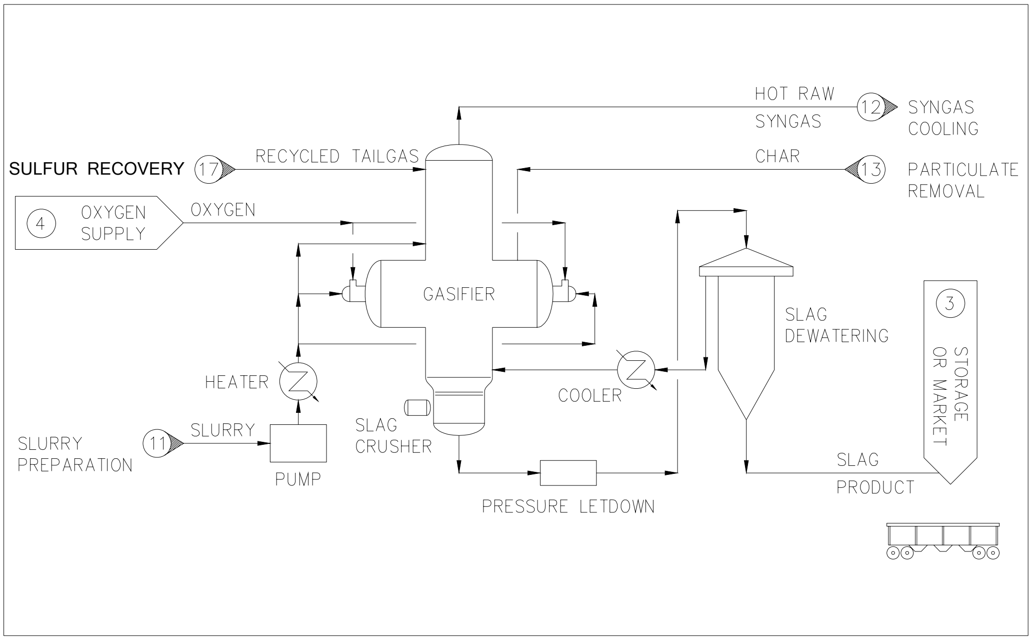
Note that the SO_2 emission rate used in this example approximates the maximum 30-day rolling average emission rate of 0.026 pounds per million Btru heat input expected from Mesaba One and Mesaba Two (see Appendix A-1). This emission rate is far lower than the New Source Performance Standard SO_2 emission rate imposed by Federal law for coal-fueled steam electric generating units shown in Figure 2.4-3.

Figure 2.4-3 New Source Performance Standard vs. Mesaba One and Mesaba Two SO_2 Emission Rates



As to production of slag, mineral matter in the feedstock and added flux forms the molten slag, which flows continuously through a tap hole in the floor of the gasifier horizontal section into a water quench bath, located below the first stage. The characteristics of the slag produced in the gasifier will vary with the mineral matter content of the feedstock. As depicted in Figure 2.4-4, the solidified slag exits the bottom of the quench section, is crushed, and flows through a continuous pressure-letdown system as a slag/water slurry. This continuous slag removal technique eliminates high maintenance, problem-prone lockhoppers and prevents the escape of raw syngas to the atmosphere during slag removal. The slag/water slurry is then directed to a dewatering and handling area (described later). The raw syngas generated in the first stage flows up from the horizontal section into the second stage of the gasifier.

Figure 2.4-4. Gasification and Slag Handling



Typically, the ash content of the coal feedstock will be in the range of 5-11%, as received. Ash in petroleum coke is expected to average about 0.6%, as received. Slag production at full load will vary from about 500 tons per day up to a maximum of about 800 tons per day per phase. The slag will be conveyed from the slag dewatering unit to the slag storage pile using covered conveyors. The slag storage area will be provided with dust suppression systems. Slag from the storage area will be conveyed to rail cars or trucks for transport to market or storage.

The gasifier second stage is a vertical refractory-lined vessel in which additional slurry is reacted with the hot syngas stream exiting the first stage. The feedstock undergoes devolatilization (separation of organic components) and pyrolysis (high temperature decomposition), thereby generating more syngas with higher heat content (less carbon being converted to CO_2) since no additional oxygen is introduced into the second stage. This additional slurry lowers the temperature of the syngas exiting the first stage by the endothermic nature of the devolatilization and pyrolysis reactions. In addition to the above reactions, water reacts with a portion of the carbon to produce additional CO and H_2 for subsequent use as syngas fuel for power generation and CO_2. Unreacted solid fuel (carbonaceous char) is carried out of the second stage with the syngas.

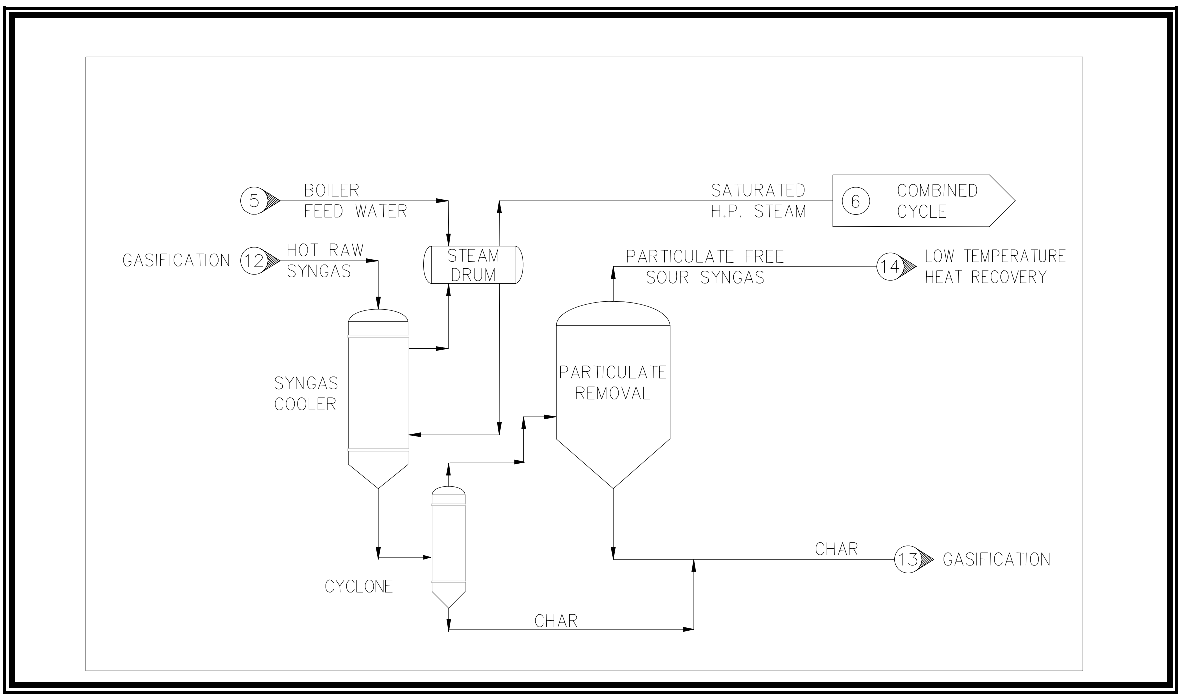
Certain metals present in the feedstocks in trace quantities and volatile at the temperatures typical of the gasifier will also be carried out in their gaseous state as components of the syngas, and removed in the cleanup stage.

The slag/water slurry will flow continuously into a dewatering bin. The bulk of the slag will settle out in the bin while water overflows into a basin in which the remaining slag fines will settle. The clear water from the settler will pass through heat exchangers where it will be cooled as the final step before being returned to the gasifier quench section. Dewatered slag is transferred to the slag storage area to be loaded into trucks or rail cars for transport to market or storage. The slurry of fine slag particles from the bottom of the settler will be recycled to the slurry preparation area to be fed back into the gasifier, ensuring maximum carbon utilization.

2.4.3 Syngas Cleanup and Desulfurization

As shown in Figure 2.4-5, the next two steps in the process are to cool the syngas and then remove the particulate matter for recycle to the gasifier. Captured particulate matter is recycled back to the gasifier The hot raw syngas exiting the gasifier system and containing entrained particulate matter will be cooled in the syngas cooler, converting a significant portion of the heat from the gasifier to high pressure steam for use in power generation.

Figure 2.4-5. Particulate Matter Removal



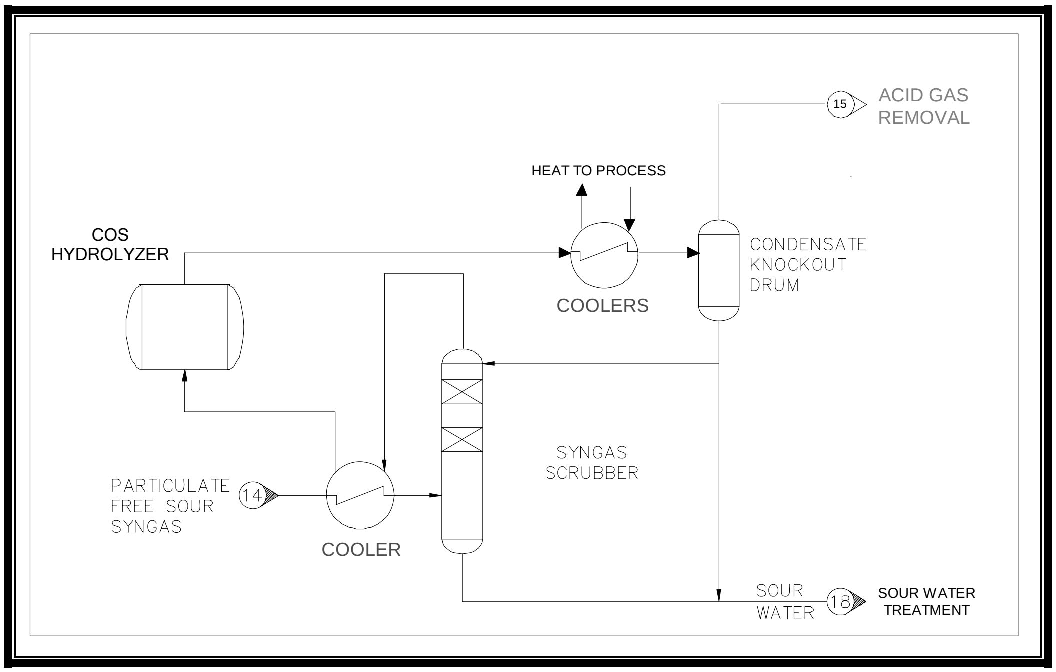
2.4.3.1 Particulate Matter Removal

After cooling, the syngas is directed to the particulate matter removal system, as shown in Figure 2.4-5 above. The gas flows first through a hot gas cyclone for removal of relatively large particulate matter and then passes to the particulate matter filter. The filter vessel contains numerous porous filter elements to remove particulate matter. The cleaned syngas exits the unit as a particle free syngas. Particulate matter removal efficiency is expected to approach 99.9%. Removed particulate matter from both the hot gas cyclone and the dry filter vessel is recycled to the first stage of the gasifier to improve carbon conversion efficiency. With the particulate matter being recycled to the gasifier from both devices, near complete gasification of the carbon content of the feedstock is obtained. The particle free syngas proceeds to the low temperature heat recovery system.

2.4.3.2 Syngas Scrubbing, COS Hydrolysis and Low Temperature Heat Recovery

With particulate matter removed from the syngas, additional gas cleanup and cooling can more easily be performed. The syngas is scrubbed with recycled sour water (water with dissolved sulfur compounds and other contaminants condensed from the syngas) to remove chlorides and trace metals and to reduce the potential of equipment corrosion and formation of undesirable products in the acid gas recovery ("AGR") system. This is shown in Figure 2.4-6.

Figure 2.4-6 Syngas Scrubbing

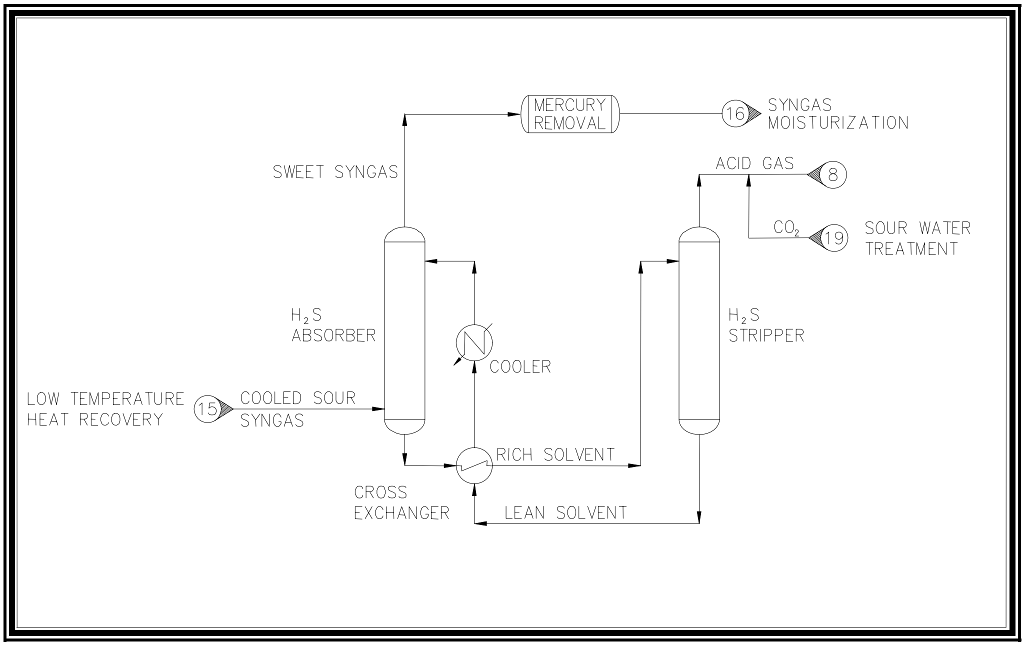


A COS hydrolysis unit is provided to achieve a high level of sulfur removal. The purpose of the COS hydrolysis step is to convert the small amount of COS in the syngas to H_2S, which can then be efficiently removed in the AGR system. After hydrolysis, the syngas is cooled in process heat exchangers to efficiently utilize the available relatively low-temperature heat. Most of the ammonia (NH_3) and a small portion of the CO_2 and H_2S present in the syngas are absorbed in the water condensed by this cooling step. Additionally, some of the trace metals that remained in their gaseous state during the particulate matter removal process will condense. The water is collected and sent to the sour water treatment unit. The cooled sour syngas is fed to the AGR system where the sulfur compounds are removed to produce a low sulfur product syngas.

2.4.3.3 Acid Gas Removal System

The AGR system (shown in Figure 2.4-7) contacts the cool sour syngas with an aqueous solution of MDEA, an amine absorbent that removes the H_2S to produce a clean product syngas. MDEA chemically bonds with H_2S, with a bond that can be easily broken with low level heat in order to regenerate the absorbent. H_2S is absorbed from the syngas by contacting the gas with MDEA solution within the H_2S absorber column. A portion of the CO_2 is also absorbed as well. The H_2S-rich MDEA from the bottom of the absorber flows to a cross heat exchanger to recover heat from the hot lean MDEA coming from the stripper. The heated rich MDEA is then directed to the H_2S stripper where the H_2S and CO_2 are removed at near atmospheric pressure. A concentrated stream of H_2S and CO_2 exits the top of the H_2S stripper and flows either to the carbon-capture system or directly to the SRU. The lean MDEA is pumped from the bottom of the stripper to the heat exchanger. The lean MDEA is further cooled before being stored and then recirculated to the absorber. This unit is a totally enclosed process with no discharges to the atmosphere.

Figure 2.4-7. Acid Gas Removal



2.4.3.4 Potential Carbon Capture Retrofit

The Applicant believes that some form of Federal greenhouse gas emissions control will be imposed within the next ten years. To provide the State and consumers with a means to deal with such requirements, the Applicant will design Mesaba One and Mesaba Two to be carbon capture ready. Additionally, the Applicant has contracted with the University of North Dakota Energy and Environmental Research Center ("EERC") to assess CO_2 management options for Mesaba One and Mesaba Two. This work is part of the Plains CO_2 Reduction Partnership,[1] Phase II efforts EERC is conducting for DOE to validate the most promising sequestration technologies and infrastructure concepts identified during Phase I of the Program.[2] Sink-source pairs, specific to the composition of CO_2 gas streams that can be removed from the syngas

[1] The Plains CO_2 Reduction Partnership is one of seven regional partnerships funded by the U.S. Department of Energy's National Energy Technology Laboratory Regional Carbon Sequestration Partnership Program.

[2] Plains CO_2 Reduction ("PCOR") Partnership Phase I Final Report/Quarterly Technical Progress Report for the Period July 1-September 30, 2005; DOE Cooperative Agreement No. DE-PS26-03NT41982 EERC Fund Nos. 4251, 4334, 4406, and 9039, January 2006.

produced by Mesaba One and Mesaba Two, will be identified and ranked according to engineering, economic, and public-acceptance considerations.

The carbon capture system that the Applicant will seek to engineer on a preliminary basis can be added after the IGCC plant is in operation. Based on work to date, such CO_2 capture facilities will likely be located within the existing IGCC Power Station Footprint and require an area of approximately 100' X 150' to accommodate necessary equipment. The preferred location for the future plot space would be adjacent to the power block. For PRB coal, the Applicant would expect to capture approximately one third of the carbon (as CO_2) in the solid IGCC feedstock. This capture would likely come at a decrease in capacity and efficiency of the IGCC plant.[3]

2.4.3.5 Mercury Removal and Moisturization

Fixed beds of activated carbon will be provided to remove residual mercury from syngas (see Figure 2.4-7 above). Multiple beds specially impregnated to remove mercury are used to obtain optimized adsorption. The activated carbon capacity for mercury ranges up to 20% by weight of the carbon (Parsons, 2002). The mercury removal system will remove enough mercury from the syngas so that the mercury content of the syngas fuel is no more than 10% of the mercury contained in the solid IGCC feedstock. The mercury removal system will be located immediately upstream or immediately downstream of the AGR. The location will be determined during the next engineering phase of the project by working closely with carbon suppliers to identify the optimum location. After acid gas and mercury removal, the product syngas is moisturized, heated, and diluted with nitrogen for control of nitrogen oxides (“NO_x”) before being combusted for power generation in the CTGs.

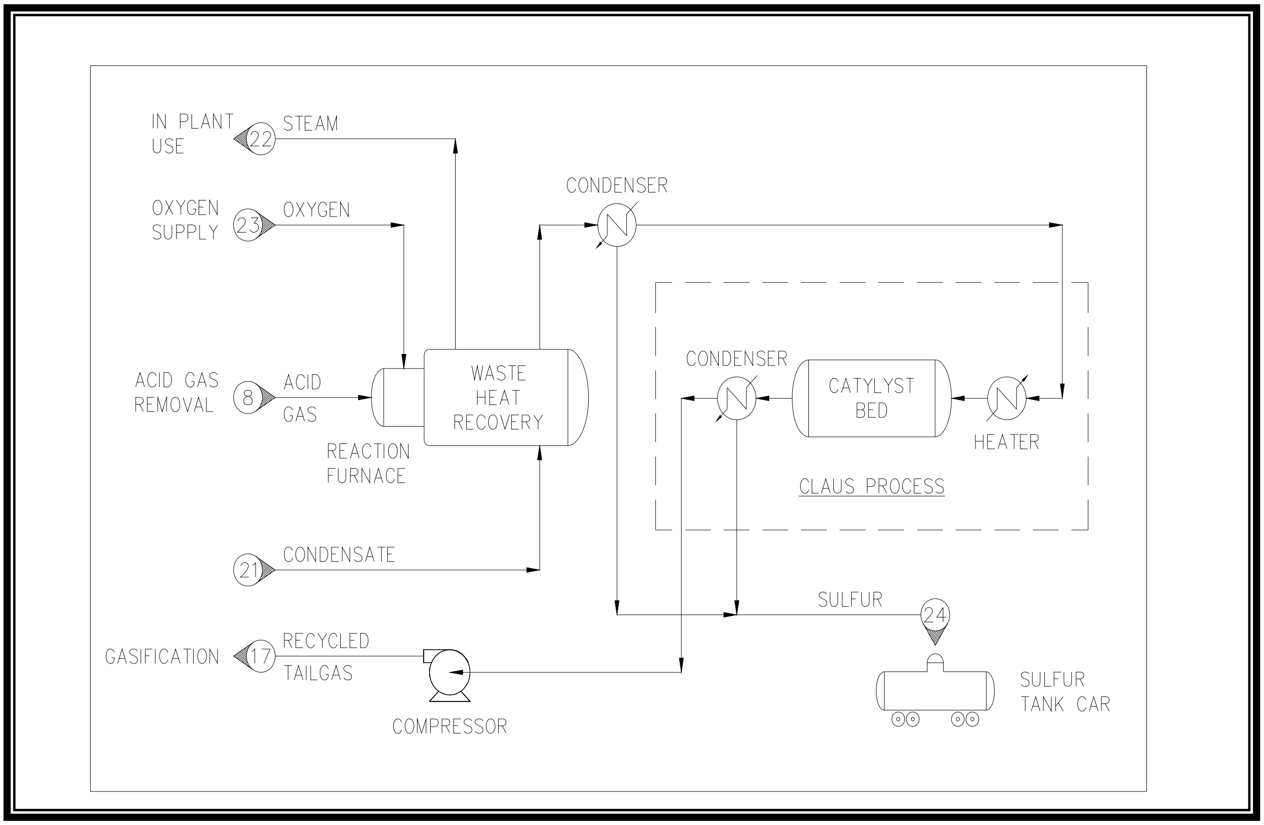
2.4.4 Sulfur Recovery Unit

The H_2S carried along in the acid gas from the AGR system is converted to elemental sulfur in the SRU. This technology is based on the industry-standard Claus process involving the conversion of the H_2S to gaseous elemental sulfur and steam. The sulfur is selectively condensed and collected in molten form (see Figure 2.4-87).

The acid gas stream from the AGR units and the CO_2 /H_2S stripped from the sour water are fed to the SRU. One-third of the H_2S is combusted with oxygen to produce the proper ratio of H_2S and SO_2, which are then reacted together to produce elemental sulfur gas in a reaction furnace. A waste heat boiler is used to recover heat before the furnace off-gas is cooled to condense the first increment of sulfur.

[3] The adverse economic and operational impacts associated with carbon capture are expected to be reduced by research and development initiatives presently underway as part of the DOE’s Clean Coal Power Initiative. Future research under that initiative will develop the technological path required to achieve removal of an expected 90% of the total CO_2.

Figure 2.4-8. Sulfur Recovery Unit



Gas exiting the first sulfur condenser is fed to a series of heaters, catalytic reaction stages and sulfur condensers where the H_2S is incrementally converted to elemental sulfur. The sulfur is recovered and stored in molten form and may be sold as a by-product raw material for fertilizer and other beneficial uses. If not sold, the sulfur will be stored on site and/or transported to a storage facility.

The tail gas from the SRU is composed mostly of CO_2 and nitrogen with trace amounts of H_2S and SO_2 as it exits the last condenser. This SRU tail gas is catalytically hydrogenated to convert the remaining sulfur species to H_2S and then recycled to the gasifier. Recycling the SRU tail gas allows for a very high overall sulfur removal in the IGCC process and eliminates the need for a conventional tail gas treating unit and reduces overall plant emissions of SO_2 and NO_x emissions to the atmosphere.

The sulfur production rate is dependent upon the sulfur content of the feedstock, and will vary from about 30 tons per day up to about 165 tons per day for each IGCC unit. The sulfur storage tanks are considered part of the SRU system.

Condensed sulfur from the SRU is collected in the sulfur pit. The liquid sulfur drains into the pit which contains a pump well and sulfur pumps. Sweep nitrogen is introduced into the pit to prevent the accumulation of an otherwise potentially explosive mixture of H_2S and air, and to control fugitive emissions. The sweep nitrogen inlet and outlet are located at opposite ends of the pit to ensure proper sweep of the vapor space. The sweep nitrogen outlet is collected and recycled to the second stage of the gasifier. Nitrogen is used instead of air as it is readily available from the ASU and since it is undesirable to return air back to the gasifier's second stage.

The liquid sulfur is pumped from the sulfur pit to a sulfur degassing unit. The sulfur degassing unit strips dissolved H_2S out of the liquid sulfur. The degassed sulfur is pumped from the degassing unit to the sulfur storage tank. The stripped H_2S stream is routed to the tail gas recycle stream to the gasifier.

Sulfur loading involves pumping liquid sulfur from the sulfur storage to trucks or rail cars. The sulfur loading arms have vapor recovery systems to control fugitive emissions by returning displaced vapors to the storage tank.

The SRU is a totally enclosed process with no discharges to the atmosphere.

2.4.5 Air Separation Unit

The air separation unit provides oxygen for the gasification process and nitrogen for CTG NO_x control and for purging. The ASU contains an air compression system, an air separation cryogenic distillation system ("cold box"), an oxygen pump system and a nitrogen compression system. Two ASU equipment trains will be provided for each phase of the facility.

A multi-stage, electric motor-driven centrifugal compressor compresses filtered atmospheric air that may be combined with additional compressed air extracted from the gas turbines in the power block. The combined air stream is cooled and directed to the molecular sieve absorbers where moisture, carbon dioxide and atmospheric contaminants are removed to prevent them from freezing in the colder sections of the plant. The dry carbon dioxide-free air is separated into oxygen and nitrogen in the cryogenic distillation system. A stream containing mostly oxygen is discharged from the cold box as a liquid and stored in an intermediate oxygen storage tank, from which it is fed to the gasifier.

The remaining portion of the air is mainly nitrogen and leaves the ASU in three separate nitrogen streams. A small portion of the nitrogen is high purity and is used in the gasification plant for purging and inert blanketing of vessels and tanks. The largest, but less pure, portion of the nitrogen is compressed and sent to the combustion turbines for NO_x emission control. Excess nitrogen is vented to the atmosphere. There will be no emission of regulated air pollutants from the ASU.

2.4.6 Slag Handling, Storage and Loading

The slag/water slurry from the gasifier (see Figure 2.4-4) flows continuously into a dewatering bin. The bulk of the slag settles in the bin while water overflows into a settler in which the remaining slag fines are settled and concentrated. The slurry of fine slag particulates from the bottom of the settler is recycled to the slurry preparation area, ensuring maximum carbon utilization. The clear water from the settler is passed through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section.

Dewatered slag is transferred by in-plant trucks to the slag storage area from where it will be loaded into on-road trucks or rail cars for transport to market or storage. The dewatered slag is relatively inert. At this point, it is also very moist and will not be a source of fugitive particulate matter emissions.

2.4.7 Combined Cycle Power Block

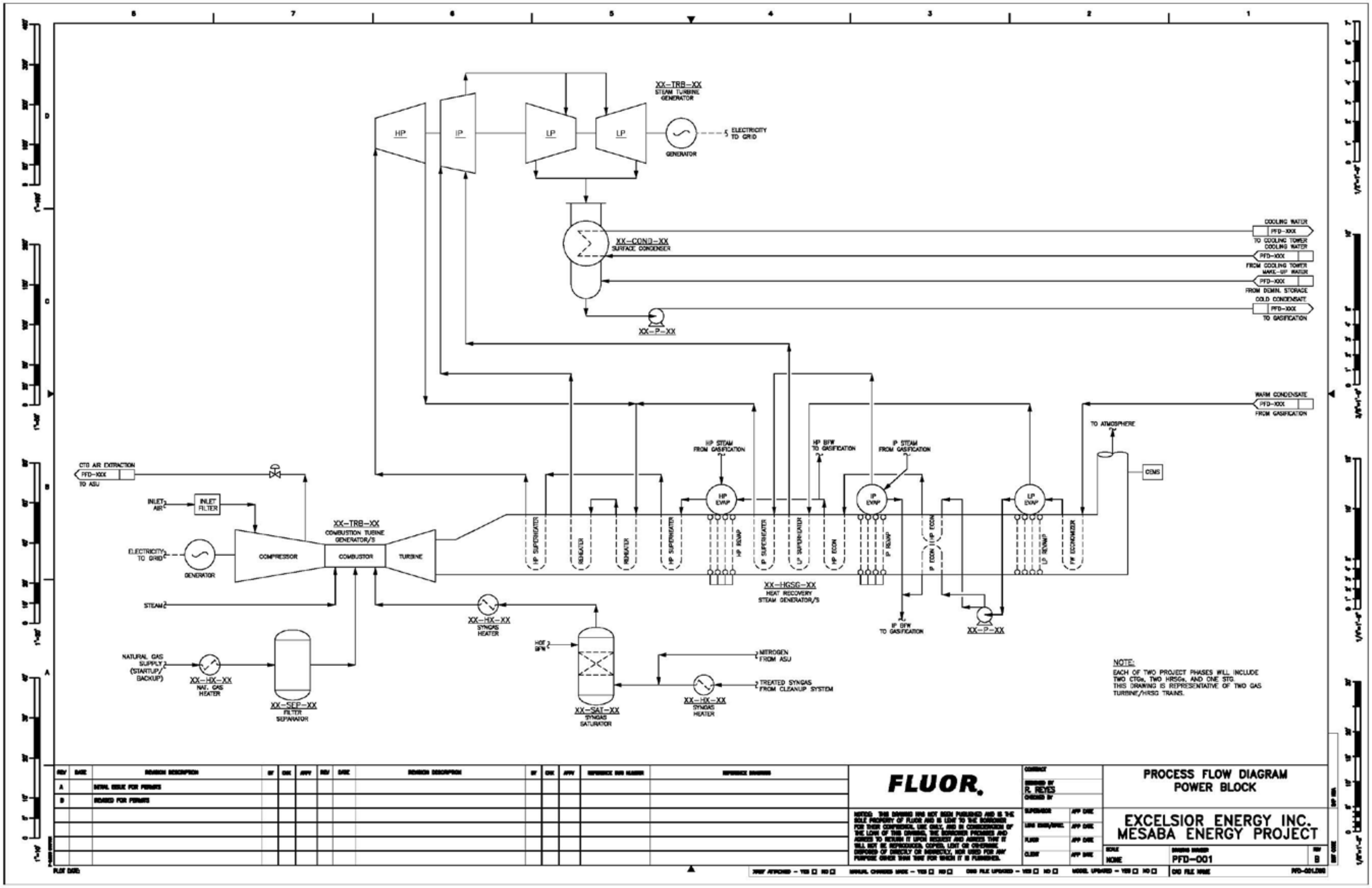
The power generation portion of the IGCC Power Station is similar to a conventional natural gas combined cycle plant. Combined cycle power generation is one of the most efficient commercial electricity generation technologies currently available. Each phase of the IGCC Power Station will include two “F Class” advanced CTGs configured to utilize syngas, two HRSGs, and a single STG. (See Figure 2.4-9). The CTGs will convert the chemical energy contained in the syngas fuel to electricity both directly through the generators integral to the CTGs, and indirectly through the additional thermal energy contained in the CTG exhaust gas. The exhaust gas is converted to high-energy steam in the HRSGs and subsequently to a significant amount of additional electricity in the STGs.

Preheated syngas from the gasification section and compressed air are supplied to the combustion turbine combustor and mixed through diffusion (a diffusion flame combustion turbine). Diluent nitrogen added to the syngas fuel reduces the flame temperature in the combustor and thereby reduces production of nitrogen oxides. The hot exhaust gas exiting the combustor flows to the expander turbine, which drives the generator to produce electricity and also turns the air compressor section of the combustion turbine. Hot exhaust gas from the expander is ducted through the HRSG to generate high-energy steam used to produce additional electricity in the steam turbine generator. Following heat recovery, the cooled CTG exhaust gas is discharged to the atmosphere through the HRSG stacks. The HRSG stacks will be provided with emission monitoring instruments as required to verify compliance with applicable emission standards and permit conditions.

The HRSG generates three pressure levels of steam as well as heating boiler feed water for the syngas cooler in the gasification section. The HRSG also provides additional energy for superheating steam from the gasification section and cold reheat steam from the STG.

The steam turbine generator is comprised of high pressure (“HP”), intermediate pressure (“IP”), and low pressure (“LP”) turbine sections, coupled directly to a generator. The LP turbine section exhausts to the surface condenser. Process heat from the gasification plant is used to preheat the condensate from the steam turbine condenser before it is returned to the HRSG to produce steam. STG exhaust steam is condensed in the surface condenser by indirect cooling with circulating cooling water from the cooling tower. The resulting steam condensate is recycled to the HRSG and other heat recovery equipment to once again produce steam for the STG.

Figure 2.4-9. Illustration of Combined Cycle Concept



2.5 IGCC Power Station Utility Systems

2.5.1 Tank Vent Boiler System

A tank vent collection/boiler system is used to convert each off-gas component in the tank vents to its oxidized form (SO_2, NO_x, H_2O, and CO_2) before venting to the atmosphere. The tank vent streams are composed primarily of air purged through various in-process storage tanks, and are routed to the tank vent boiler. This tank purge gas may contain very small amounts of sulfur-bearing components. The high temperature produced in the tank vent boiler thermally converts any H_2S present in the tank vents to SO_2. Heat recovery in the form of steam generation is provided for the hot exhaust gas from the tank vent boiler before it is directed to a stack.

The slag handling dewatering system off-gas contains H_2S which would be a source of relatively significant SO_2 emissions if vented to the tank vent system. In this part of the process, H_2S is released from slag water as the pressure is reduced from approximately 400 pounds per square inch gauge ("psig") to atmospheric conditions. Rather than vent this "flashed" gas to the tank vent boiler, a blower will be provided to combine it with either the tail gas from the SRU for recycle to the gasifier or the SRU feed gas from the AGR, thus eliminating this potential SO_2 emission source.

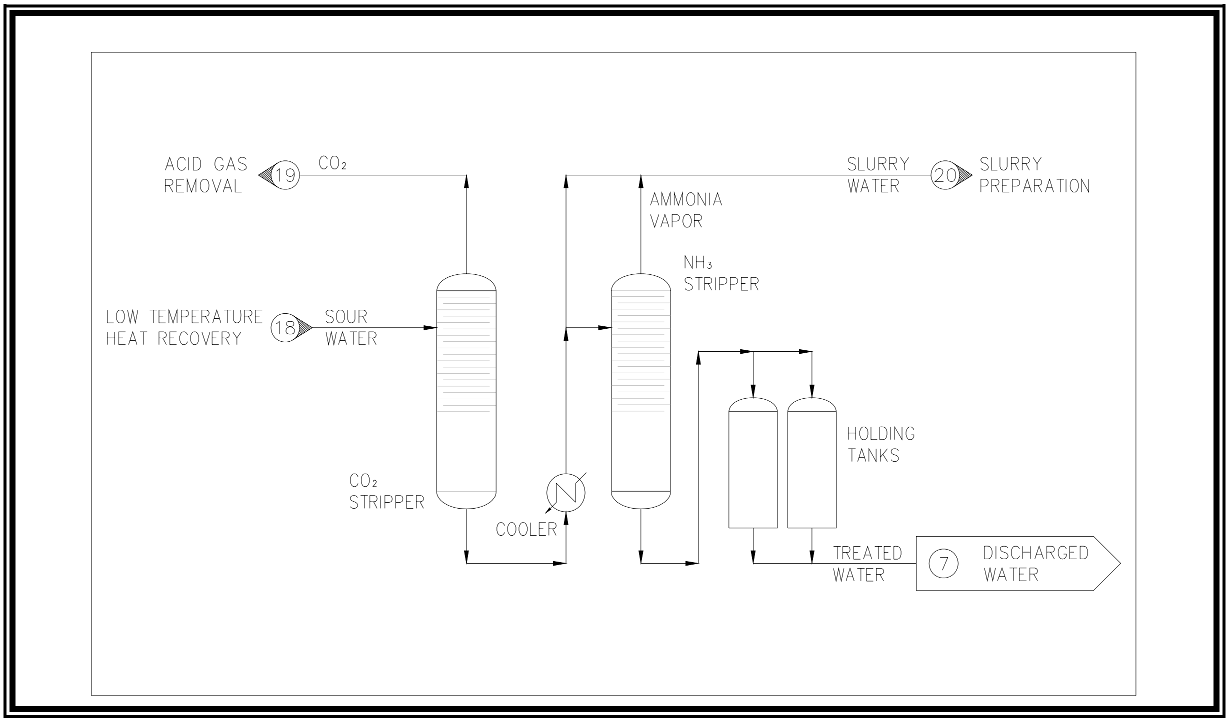
2.5.2 Sour Water Treatment

Process water containing dissolved contaminant gases produced within the gasification process must be treated to remove these dissolved gases before being recycled to the coal grinding and slurry preparation area or being blown down to the Zero Liquid Discharge ("ZLD") System. The sour water treatment process is illustrated in Figure 2.5-1. The dissolved gases are driven from the water using steam-stripping. The steam provides heat and a sweeping medium to expel the gases from the water, resulting in a purification level sufficient for reuse within the plant and/or for blowdown to the ZLD.

Water condensed during cooling of the sour syngas contains small amounts of dissolved gases (CO_2, NH_3, H_2S and other trace contaminants). The gases are stripped from the sour water in a two-step process. First, the CO_2 and most of the H_2S are removed in the CO_2 stripper column by steam stripping and directed to the SRU. The water exits the bottom of this column, is cooled, and a major portion is recycled to feedstock grinding and slurry preparation. The rest is treated in an ammonia stripper column to remove the ammonia and remaining trace components. The stripped ammonia is combined with the recycled slurry water. A portion of the ammonia-stripped water is blown down to the ZLD, with the rest being reused within the plant. Reuse of the water within the gasification plant minimizes water consumption and discharge.

This unit is a totally enclosed process with no discharges to the atmosphere.

Figure 2.5-1 Sour Water Treatment System



2.5.3 Zero Liquid Discharge System

Water from the bottom of the ammonia stripper is treated in a ZLD unit. The blowdown stream is pumped to a brine concentrator which uses steam or vapor compression to indirectly heat and evaporate water from the wastewater stream. Generated water vapor is compressed and condensed, and the high quality distillate is recycled to the syngas moisturization system or to other water uses in the plant. The concentrated brine is further processed in a heated rotary drum dryer/crystallizer. There the remaining water is vaporized and a solid filter cake material is collected for proper disposal. Use of the ZLD system effectively prevents the contaminants in feedstocks from being discharged to surface waters.

2.5.4 Auxiliary Boilers

Two auxiliary boilers, one for each phase of the IGCC Power Station, will provide steam for pre-startup equipment warm up and for other miscellaneous purposes when steam from the gasifiers or HRSGs is not available. These boilers will provide steam in addition to, or in lieu of, the steam that can be generated from the tank vent boilers. Each boiler will produce a maximum of about 100,000 lb/hr of steam and will be fueled by pipeline natural gas. Annual operation of each boiler will be equivalent to or less than 25% of the year at maximum capacity. The auxiliary boilers will be equipped with low NO_x burners to minimize air emissions.

2.5.5 Flare

The gasification island elevated flare is utilized to burn partially combusted natural gas and scrubbed/desulfurized off-specification syngas during unit startup or on-specification syngas during short-term combustion turbine outages. Syngas sent to the flare during normal planned flaring events will be filtered, water-scrubbed and further treated in the AGR and mercury removal systems to remove regulated contaminants prior to flaring. Flaring of untreated syngas or other streams within the plant would only occur as an emergency safety measure during unplanned plant upsets or equipment failures. The normal start-up sequence for the flare is discussed in Section 2.5.7 and in Tables 2.5-1 and 2.5-2.

2.5.6 Emergency Diesel Engines

For each of Mesaba One and Mesaba Two, one 2 MW emergency diesel generator will be used for the gasification island and one 350 kW emergency diesel generator will be used for the power block. One or two nominal 300 hp diesel-driven firewater pumps will be provided for each phase (emission estimates are based on having two firewater pumps for Mesaba One and two pumps for Mesaba Two). These engines will burn very low sulfur distillate oil. Other than plant emergency situations, the engines will be operated less than five hours per month per engine for routine testing, maintenance, and inspection purposes.

2.5.7 Startup and Shutdown

Two general types of plant startups will occur at the IGCC Power Station. The first type, which will probably be more usual, consists of replacing one of the two operating gasifiers (per phase) with the third, spare gasifier. This procedure would be conducted to avoid extended gasifier outages (and the resulting loss of the Station's electric generating capacity) while performing normal maintenance or repairs on the gasifier taken off line. The other startup type consists of starting up two of the three gasifiers and both combustion turbines (per phase) after the entire Station has been off line for major maintenance or some other reason. Tables 2.5-1 and 2.5-2 list the sequential steps required for each type of startup. The total number of gasifier cold startups is expected to total approximately four per year per gasifier after the IGCC Power Station has achieved commercial operation and completed all testing, inspection, and monitoring requirements.

Prior to introducing coal and/or coke slurry feed to a gasifier during startup, the gasifier must be pressurized and heated. This is accomplished by purging the gasifier vessel and downstream syngas piping with nitrogen from the ASU or storage. This purge gas flows through the normal syngas treating system and is vented to the flare for safe disposal. Nitrogen is then used to pressurize the system to test for leaks. Natural gas and oxygen from the ASU or storage is next combusted in the gasifier to gradually raise the temperature to an adequate level to begin slurry gasification. The products of combustion from heating (CO_2, CO, water vapor, and excess natural gas) also flow through the syngas treating system prior to final combustion in the flare. If available, syngas may be substituted for the natural gas fuel once stable combustion is achieved. When the gasifier has reached the required temperature, the natural gas or syngas fuel flow is stopped and coal and/or coke slurry is introduced to the gasifier (without depressurizing the gasifier or syngas piping system). The initial syngas, which is not yet suitable as combustion turbine fuel due to its low heating value, flows through the normal syngas treating system for removal of particulate matter, sulfur, mercury, and other trace contaminants and is routed to the flare for combustion. Once the syngas product meets the required heating value and other minimum specifications for CTG fuel, flow to the flare is stopped and the syngas is routed to one or more CTGs for electricity production. At this point the gasifier startup is complete.

CTGs will only be started on natural gas fuel. The startup process is relatively straightforward. First, the CTG rotor is mechanically turned without combustion to purge the CTG/HRSG gas paths of any residual combustible materials. Next, the combustor is ignited with natural gas fuel and the CTG is accelerated to full rotational speed with no load on the generator (full speed, no load). The generator is then loaded (starts producing electricity) and is ramped up (load increased) at a specified rate. Steam for NOx control is injected into the fuel combustor at the appropriate load point. Switching to syngas fuel will normally occur when the CTG reaches 50 to 70 percent of full load operation. At this point the natural gas/steam flow is gradually decreased and replaced with moisturized syngas fuel and diluent nitrogen. After completing the fuel switch, the CTG is ramped to the desired operating load point (typically full load). Startups for natural gas only backup power generation are the same as described above without the fuel switching step.

Table 2.5-1
IGCC Startup – Gasifier Replacement

(Gasifier 2 will be taken off line and replaced by Gasifer 3. Plant is initially in normal operation.)
1. Purge and pressure Gasifier 3 with nitrogen and test vessel and piping for leaks.
2. Introduce natural gas and oxygen mixture into Gasifier 3, light off, and warm up. (Once stable oxidation is achieved, treated product syngas may be substituted for natural gas.) Combustion products from warm-up flow through the syngas treating system to the flare or CTG.
3. Prior to introducing slurry feed to Gasifier 3, ramp down Gasifier 2 and shutdown. Simultaneously ramp down CTGs.
4. When adequate gasifier temperature achieved, introduce slurry and oxygen to Gasifier 3 and stop natural gas, vent syngas though treating system to flare.
5. Switch syngas from flare to CTGs when CTG fuel specifications achieved and ramp up Gasifier 3 and CTGs.
6. Nitrogen purge Gasifier 2, vent purge gas to flare.

Table 2.5-2
IGCC Cold Plant Startup

(Assumes plant utility and supporting systems, e.g., steam, cooling water, etc., are started and available when needed)
1. Cool down ASU.
2. Purge and pressure Gasifier 1 with nitrogen from storage and test vessel and piping for leaks.
3. Warm up amine unit, sulfur recovery unit and gas systems, light flare pilot.
4. Introduce natural gas from pipeline and oxygen from storage into Gasifier 1, light off, and warm up. Combustion products from warm-up flow through normal syngas treating system to flare.
5. Startup COS reactors (bypassing warm-up combustion gases), heat up sulfur recovery unit on natural gas, and start amine circulation.
6. Complete ASU startup, oxygen available.
7. Warm up HRSG and steam turbine with steam from aux boiler.
8. Startup CTG 1 on natural gas.
9. Introduce slurry and oxygen to Gasifier 1 and stop natural gas when adequate gasifier temperature achieved, vent syngas though treating system to flare.
10. Switch syngas from flare to CTG 1 when CTG fuel specifications achieved and CTG 1 is at adequate load, reduce and stop natural gas to CTG, ramp up Gasifier and CTG to required load.
11. Repeat startup sequence for Gasifier 2 and CTG 2, possibly substituting product syngas for natural gas to warm up Gasifier 2.

Emissions that will only occur during startup include:

- Natural gas (or treated syngas) combustion products - resulting from start-up of the gasifiers - that are routed to the flare to ensure complete oxidation. These combustion gases will flow through the normal syngas clean up circuit before being routed to the flare.
- Transient CO and VOC emissions as the CTGs are started up on natural gas fuel.
- Flaring of filtered, scrubbed, and desulfurized syngas after slurry is introduced to the gasfier, but before the syngas product has reached the specified composition and conditions for use in the combustion turbine.

Other plant emissions during startup will be the same or similar as during normal plant operation.

2.6 Major Process Equipment

The major functional process equipment provided for the inside-the-battery-limit ("ISBL") facilities for the IGCC Power Station are identified below. The number of trains and percentage train capacity for each of the functions/components are also identified. Capacities for some of the major components are identified.

2.6.1 *Air Separation Unit (2x 50%)*

- ASU (2,507 tons per day/train, based on PRB1 coal operation)
- N_2 Booster Compressor for CTG Injection
- Liquid Oxygen and Liquid Nitrogen storage

2.6.2 *Feedstock (Coal/Petroleum Coke) Handling (1 x 100%)*

- Feedstock Active Storage (20 days based on PRB1 coal)/Conveying/Reclaiming (based on 8,550 tons/day, as received)
- Feedstock Inactive Storage (45 days based on PRB1 coal)
- Flux Storage (silos)/Conveying/Reclaiming (250 tons/day based on 50:50 blend of PRB2:PRB3 coals)
- Rotary Railcar Unloading Facilities and Thaw Shed (Feedstock)
- Dust Collectors for enclosed feedstock storage areas
- Truck Unloading Facilities (Flux)

2.6.3 *Gasification Island (3 x 50%)*

- Feedstock Grinding and Slurry Preparation (2 x 60%)
- Gasification (4,275 tons per day design coal, as received, per gasifier, based on PRB1 coal)
- High Temperature Heat Recovery
- Dry Char Removal
- Particulate Matter Removal
- Slag Grinding (1 x 100%)
- Slag Dewatering (1 x 100%)
- Slag Storage and Loading System (1 x 100%) (800 tons per day (wet basis), based on 50:50 blend of PRB2:PRB3 coals)

2.6.4 *Syngas Treating (2 x 50%)*

- Syngas Scrubbing
- Low Temperature Syngas Cooling
- COS Hydrolysis
- Recycle Gas Compression
- Acid Gas Removal
- Acid Gas Enrichment (1 x 100%)
- Mercury Removal
- Syngas Moisturization
- Sour Water System (1 x 100%)

2.6.5 *Sulfur Recovery and Tail Gas Recycle (2 x 50%)*

- Claus Plant Sulfur Recovery (O_2-Blown), (Up to 83 tons per day/train, based on high sulfur Illinois No. 6 operation)

- Molten Sulfur Storage
- Molten Sulfur Truck/Rail Loading Facilities (1 x 100%)
- Tail Gas Recycle (1 x 100%)
- Tank Vent Gas Incineration (1 x 100%)

2.6.6 *Power Block*

- CTG (2 x 50%) (220 MW nominal each, based on Siemens-Westinghouse SGT6-5000F combustion turbine assumed for environmental permitting)
- HRSG and Exhaust Stack (2 x 50%)
- STG (1 x 100%), (Up to 300 MW nominal)
- Surface Condenser (1 x 100%)
- Vacuum, Condensate and Boiler Feedwater Systems (1 x 100%)
- Power Block Circulating Water System
- Raw Water/Demineralizer Water Tankage/Pumps
- Demineralizer System
- Filtered Raw Water, Firewater/Tankage/Pumps
- Wastewater Collection/Wastewater Separation
- Plant and Instrument Air
- Step-up Transformers

2.6.7 General Facilities (1 x 100%)

- Gasification/ASU Cooling Water/Tower System
- ZLD Unit (for Process Condensate Blowdown)
- Process Condensate Blowdown Holding Tank
- Gasification Unit Flare
- Emergency Diesel Generator
- Natural Gas Distribution
- Plant Drains
- Nitrogen Distribution
- Potable and Utility Water
- Sanitary Sewage System
- Storm Water Collection and Treatment

2.6.8 Expected Process Operating Characteristics

As noted previously in Section 1.6.3, feedstock variability has been considered along with critical equipment components and operating conditions known to influence plant performance (for example, the combustion turbine selected, its operating mode, the operating mode of the gasifier, and ambient conditions) to identify the operating conditions which would provide a reasonable upper limit or “worst case” scenario for potential pollutant emissions/discharges. Table 1.6-1 quantifies such conditions assuming operation of the gasifier in PSQ mode while Table 1.6-2 assumes operation of the gasifier in FSQ mode. Pollutant emissions, discharges, and waste products are quantified assuming the conservative PSQ conditions (see Sections 1.8 and 4.0).

Table 2.6-1 Key Performance Indicators Used to Assess Worst Case Environmental Impacts Of IGCC Power Station (Phase I, PSQ Mode)

Performance Parameter	Estimated Range	Comments
CTG gross power, MW	440	Total for two CTGs
STG gross power, MW	265 – 300	Varies depending on quantities of steam generated by Gasification Island and HRSGs
Net plant generation, MW	580 – 606	Output from CTGs plus STG, less internal consumption and losses
Coal/coke feed rate, tons/day (as received)	5,300 – 8,550	Feed rate to gasifiers
Coal/coke feed energy, million Btu/hr (HHV)	5,280 – 5,910	Energy content of gasifier feedstock
Product syngas energy, million Btu/hr (HHV)	4,190 – 4,368	Energy content of syngas fuel delivered to CTGs
Coal conversion efficiency	0.71 – 0.80	Fraction of solid feedstock energy in syngas feed to CTGs
Net overall heat rate, Btu/kW-hr (HHV)	8,900 – 9,500	Solid feedstock energy used per unit of net electricity to grid
Flux feed, tons/day	0 – 250	Conditioning agent for gasifier feedstock
Slag by-product production, tons/day	500 – 800	Varies depending on feedstock composition and flux use
Sulfur by-product production, tons/day	30 – 165	Varies depending on feedstock composition

Table 2.6-2 Expected IGCC Power Station Operating Characteristics (Phase I, FSQ Mode)

Feedstock	PRB-1	PRB-1	PRB-1	50/50 Wt% PRB2/PRB3	Illinois No. 6	Sizing Basis
Ambient Temperature:	38°F	80°F	-20°F	38°F	38°F	
Power Generation						
SW SGT6-5000F CTG (x2)	440 MW	440 MW	440 MW	440 MW	440 MW	440 MW
STG	300 MW	300 MW	288 MW	N/A	N/A	300 MW
Gross Power	740 MW	741 MW	728 MW	N/A	N/A	741 MW
Less ASU Auxiliary Load	- 98 MW	-106 MW	- 97 MW	N/A	N/A	N/A
Less Internal Consumption	- 37 MW	- 37 MW	- 35 MW	N/A	N/A	N/A
Net Power (for Export to Grid)	606 MW	598 MW	596 MW	N/A	N/A	606 MW
Coal Feed (as received), tons/day	8225	8119	8136	7397	5477	8225
Coal Feed (dry), tons/day	5716	5643	5655	5461	4957	5716
Coal Feed (HHV), MMBtu/hr	5688	5616	5627	5592	5288	5688
Plant Heat Rate (HHV), Btu/kWh	9391	9397	9439	9412	9033	N/A
Oxygen Feed (contained), tons/day	5014	4950	4960	5005	3894	5014
Flux Feed, tons/day	0	0	0	233	0	
Design capacity, tons/day						233

Feedstock	PRB-1	PRB-1	PRB-1	50/50 Wt% PRB2/PRB3	Illinois No. 6	Sizing Basis
Slag Produced, tons/day	501	495	496	774	772	
Design capacity, tons/day						774
Sulfur Produced, tons/day	30	29	29	45	162	
Design capacity, tons/day						162

The composition and properties of the product syngas will vary depending on the solid feedstocks processed and Power Station operating conditions. Table 2.6-3 shows the expected range of syngas composition and fuel heating value.

Table 2.6-3
Estimated Product Syngas Composition Multiple Feedstock Plant (Phase Independent)

Component [1]	Range
Hydrogen, vol %	30 – 40
Carbon monoxide, vol%	35 – 50
Carbon dioxide, vol%	13 – 26
Methane, vol%	1 – 5
Nitrogen plus argon, vol%	2 – 3
Higher heating value, Btu/scf [2]	240 – 305

[1] Parameters shown for dry syngas fuel (water excluded), prior to nitrogen dilution.
[2] Standard conditions defined as 60 degrees Fahrenheit ("° F"), one atmosphere pressure.

3. AIR QUALITY STANDARDS AND REGULATORY ANALYSIS

This section describes the air quality standards and regulations that apply to the proposed IGCC Power Station. Federal and State regulations limit the amount of emissions from power plants and other sources in order to protect and preserve air quality and public health. The following sections describe the applicable regulations and resulting requirements for the proposed facility.

3.1 Ambient Air Quality Standards

The U.S. Environmental Protection Agency (EPA) Office of Air Quality Planning and Standards (OAQPS) has set National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health and the environment. Primary standards are intended to protect public health, including the health of sensitive populations such as children and the elderly. Secondary standards are intended to protect public welfare, including protection against decreased visibility, and damage to animals, crops, vegetation and buildings. The NAAQS standards are set forth in Table 3.1-1.

Table 3.1-1
National Ambient Air Quality Standards for Criteria Pollutants

Pollutant	Averaging Period	Primary NAAQS ($\mu g/m^3$)	Secondary NAAQS ($\mu g/m^3$)
SO_2	3-hour	None	1300
	24-hour	365	None
	Annual	80	None
PM_{10}	24-hour	150	150
	Annual	50	50
$PM_{2.5}$	24-hour	65	65
	Annual	15	15
NO_x	Annual	100	100
CO	1-hour	40,000	None
	8-hour	10,000	None
Ozone	8-hour	157	None
Lead	Quarterly	1.5	1.5

In addition, Minn. R. 7009.00800 sets out the State of Minnesota Ambient Air Quality Standards (MAAQS), which includes the six criteria pollutants, hydrogen sulfide (H_2S) and Total Suspended Particulate Matter (TSP). The MAAQS are set forth in Table 3.1-2.

Table 3.1-2
Minnesota Ambient Air Quality Standards (MAAQS)

Pollutant	Averaging Period	Primary MAAQS ($\mu g/m^3$)	Secondary MAAQS ($\mu g/m^3$)
SO_2	1-hour	1300	None
	3-hour	None	1300*
	24-hour	365	None
	Annual	80	60
TSP	24-hour	260	150
	Annual	75	60
PM_{10}	24-hour	150	150
	Annual	50	50
$PM_{2.5}$	24-hour	65	65
	Annual	15	15
NO_x	Annual	100	100
CO	1-hour	35,000	35,000
	8-hour	10,000	10,000
Ozone	8-hour	157	157
Lead	Quarterly	1.5	1.5
Hydrogen Sulfide (H_2S)	½-hour (not to be exceeded twice/yr)	70	
	½-hour (not to be exceeded twice in 5 days)	42	

* Not to exceed 915 µg/m3 in northern Minnesota (Air Quality Regions 127, 129, 130, and 132).

3.2 Attainment Status

The IGCC Power Station will be located within the city of Taconite, in Itasca County, Minnesota. The entire state of Minnesota is classified as in attainment with the NAAQS. In addition, the area is in attainment with the MAAQS.

3.3 New Source Review and Prevention of Significant Deterioration

This section discusses the applicability and general requirements of the Federal New Source Review (NSR) Regulations. These regulations include permitting requirements for new or modified major stationary sources located in non-attainment and attainment areas. Since the IGCC Power Station has emissions of at least one regulated pollutant over 100 tons per year, it is considered a major source and is subject to the NSR regulations. Major sources located in attainment areas are required to comply with “Prevention of Significant Deterioration” (PSD) regulations, which are contained in 40 C.F.R. § 52.21, and incorporated by reference into Minn. R. 7007.3000.

An additional criterion of PSD applicability for a new project is that the amount of any one regulated pollutant emitted by the project must be equal to or greater than significance levels defined by the rule. This evaluation of significance is done on a pollutant-by-pollutant basis. Mesaba One and Mesaba Two have emissions above the PSD significance levels for nitrogen oxides (NO_x), sulfur dioxide ("SO_2"), CO, volatile organic compounds ("VOC"), hydrogen sulfide ("H_2S") and particulate matter less than 10 microns in aerodynamic diameter ("PM_{10}"). Therefore, PSD review is required under the regulations, as demonstrated in Table 3.3-1.

Table 3.3-1
Total IGCC Power Station Emissions

Pollutant	PSD Significance Threshold (TPY)	Plantwide Potential to Emit (TPY)	PSD Review Required?
Carbon Monoxide	100	2,539	Yes
Nitrogen Oxides	40	2,872	Yes
Sulfur Dioxide	40	1390*	Yes
Particulate Matter (PM)	25	503	Yes
Particulate Matter < 10 microns (PM_{10})	15	493	Yes
Ozone (VOC)	40	197	Yes
Lead	0.6	0.03	No
Sulfuric Acid Mist	7	130	Yes
Hydrogen Sulfide	10	17	Yes

*The sulfur dioxide emissions in this table have not been adjusted to account for the formation of sulfuric acid aerosol which is calculated assuming a specified conversion of SO_2 to such species. See Form GI-09C in Section 9 to identify the extent to which SO_2 emissions would decrease taking into account such conversion.

The required PSD review consists of the following elements:

- A case-by-case Best Available Control Technology (BACT) demonstration, which takes into account energy, environmental, and economic impacts as well as technical feasibility. Section 5 of this application provides a BACT analysis demonstrating that the project will achieve the maximum degree of emissions reduction achievable given these considerations.
- An ambient air quality impact analysis to demonstrate that the allowable emissions from the proposed project will not cause or contribute to a violation of the applicable PSD increments and NAAQS. This analysis is presented in Section 7 of this application.
- An assessment of the direct and indirect effects of the proposed project on general growth, soil, vegetation, and visibility. Additionally, a source that might impact a Class 1 Federal area must undergo additional review. These assessments are discussed in Section 7.
- An ambient air quality monitoring program for up to one year may be required if no other representative data are available and if the project impacts are greater than a monitoring de minimis level. The analysis in Section 7 demonstrates that the project impacts are below these threshold levels and no pre-construction monitoring is required.

- Public comment, including an opportunity for a public hearing. This requirement may be addressed by the Minnesota Pollution Control Agency (MPCA) during joint formal public hearings to finalize the Environmental Impact Statement required under State law and the PSD permit.

3.4 New Source Performance Standards (40 C.F.R. Part 60)

New Source Performance Standards (NSPS) have been developed by the EPA for specific source categories. These standards are codified in the Code of Federal Regulations (C.F.R.) under Part 60 (40 C.F.R. 60) based on the equipment to be installed or modified. The standards that apply to Mesaba One and Mesaba Two are as follows:

- Subpart A – General Provisions
- Subpart Da – Standards of Performance for Electric Utility Steam Generating Units For Which Construction is Commenced After September 18, 1978 (IGCC Combustion Turbines)
- Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (Auxiliary Boiler)
- Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (Tank Vent Boiler)
- Subpart HHHH - Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units (Hg Budget Trading Program General Provisions)
- Subpart Y - Standards Of Performance For Coal Preparation Plants

3.4.1 General Provisions (40 C.F.R. 60 Subpart A)

40 C.F.R. 60 subpart A provides for general notification, record keeping, and monitoring requirements. As specified in 40 C.F.R. 60.1, the requirements contained in Subpart A apply to emission units subject to a regulation contained in 40 C.F.R. 60 (NSPS regulations), unless the applicable NSPS regulation specifically exempts the emission unit from the provisions of Subpart A.

40 C.F.R. 60.8 requires an initial performance test. This part states that an initial performance test should be conducted within 60 days after achieving the maximum production rate at which the source will be operated, but not later than 180 days after initial startup of such source. The specific test methods and procedures to comply with 40 C.F.R. 60.8 are specified in 40 C.F.R. 60.335.

3.4.2 Combustion Turbines: Standards of Performance for Electric Utility Steam Generating Units (40 C.F.R. 60 Subpart Da)

As specified in Section 60.40a(b), Subpart Da applies to any electric utility combined cycle gas turbine that is capable of combusting more than 73 megawatts (250 MMBtu/hour) heat input of fossil fuel in the steam generator, and which commences construction or modification after September 18, 1978. Combustion turbine generators (CTGs) were not typically classified as electric utility steam generating units. However, in February 2005, the EPA proposed new NSPS for both utility units and CTGs (70 FR 9706 and 70 FR 8314). At that time, EPA clarified and determined that IGCC units (and the CTs that are part of IGCC units) are now to be covered as coal-fired utility units under Subpart Da, Db, or Dc, as applicable based on their size.

The proposed revisions will establish output-based limits for facilities whose construction commenced after February 28, 2005. Based on the size and design of the Mesaba One and Mesaba Two plants described in this document, Subpart Da is the applicable regulation (for electric utility steam generating units). The proposed new limits are shown in Table 3.4-1.

Table 3.4-1
Emission Limits from Proposed NSPS Subpart Da

Pollutant	Proposed Emission Limit
PM	0.015 lb/MMBtu
SO_2	2.0 lb/MWh gross energy output, based on a 30-day rolling average
NO_x	1.0 lb/MWh gross energy output, based on a 30-day rolling average

The revisions to the NSPS proposed for Subpart Da incorporate provisions from the Clean Air Mercury Rule ("CAMR") to control mercury emissions from coal- and oil-fired utility units. In addition, the following definitions were added or revised:

- **Electric Utility Steam Generating Unit** means any fossil fuel-fired combustion unit of more than 25 MW that serves a generator that produces electricity for sale…;
- **Coal** includes synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to….gasified coal
- **Coal-fired electric utility steam generating unit** means an electric steam generating unit that burns coal, coal refuse, or a synthetic gas derived from either coal exclusively, in any combination together, or in any combination with other supplemental fuels in any amount. Examples of supplemental fuels include, but are not limited to, petroleum coke and tire-derived fuels.
- **Gaseous fuel** means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, and coke-oven gas.
- **IGCC electric steam generating units** means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in combined cycle turbine.

Under the CAMR, a new section 60.45Da for mercury standards includes a specific limit for IGCC units, which is 20×10^{-6} lb/MWh or 0.000020 lb/MWh (0.0025 ng/J) on a gross electrical output basis, computed as a 12-month rolling average.

3.4.3 Combustion Turbines: Standards of Performance for Stationary Gas Turbines (40 C.F.R. 60 Subpart GG)

The proposed CTGs will not be subject to NSPS emission limitations for stationary CTGs (Subpart GG of 40 C.F.R. Part 60). The new syngas-fired CTGs associated with the IGCC Power Station will comply with the new proposed NSPS for electric utility steam generating units constructed after February 28, 2005, as listed above. In its proposed revisions to the CTG NSPS, EPA stated that it intends for IGCC units (and the CTGs included as part of IGCC units) to be regulated under the Utility NSPS (see 70 FR 8314).

3.4.4 Combustion Turbines: Proposed New Standards (40 C.F.R. 60 Subpart KKKK)

The EPA proposed new standards for CTGs on February 18, 2005 to update the NO_x and SO_2 emission standards with the performance of current CTGs and their emissions. This standard applies to new, modified, or reconstructed turbines with a power output at peak load of equal to or greater than 1 MW. In the preamble for the proposed rule (70 FR 8322), the EPA stated, "We consider gasification as an emissions control technology for solid fuels. Therefore, we consider it appropriate to cover CTGs fueled by gasified coal under the Utility NSPS." As such, the IGCC Power Station will be covered by NSPS Subpart Da as noted above.

3.4.5 IGCC: Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units (40 C.F.R. Part 60 Subpart HHHH, Hg Budget Trading Program General Provisions)

Subpart HHHH was included as part of the CAMR package promulgated on May 18, 2005 (70 FR 28606). Key definitions included in 40 C.F.R. 60.4102 for IGCC facilities are listed below:

- **Unit** means a stationary coal-fired boiler, or stationary coal-fired CTG.
- **Coal-fired** means combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year.
- **Coal-derived fuel** means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Therefore, IGCC CTGs are affected units governed by this rule, and will need to comply with the mercury budget and trading provisions outlined in Subpart HHHH.

The final rule allows two methodologies for continuously monitoring Hg emissions: (1) Hg CEMS; and (2) sorbent trap monitoring systems. New and existing units under 40 C.F.R. part 60, subpart HHHH must certify the required continuous monitoring systems and begin reporting Hg mass emissions data pursuant to the applicable compliance date in 40 C.F.R. 60.4170(b). Under 40 C.F.R. 60.49a(s), the owner/operator is required to prepare a unit-specific monitoring plan and submit the plan to the Administrator for approval, no less than 45 days before commencing the certification tests of the continuous monitoring systems. The Applicant will choose one of the applicable mercury monitoring options, and provide the required plans prior to startup of the units and their initial performance tests.

3.4.6 Coal Preparation (40 C.F.R. Part 60 Subpart Y)

Coal handling capacity at the IGCC power station will exceed 200 tons per day, and is therefore subject to these NSPS. The rule applies to coal processing and conveying equipment, coal storage systems, and coal transfer and loading systems. These units are subject to an opacity limitation of 20 percent in accordance with 40 C.F.R. 60.252(c).

3.4.7 Auxiliary Boiler: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (40 C.F.R. Part 60, Subpart Db)

The natural gas-fired auxiliary boiler will be covered by NSPS Db since its heat input will be greater than 100 MMBtu/hr. However, since the unit will be fueled only by natural gas, the only applicable limit for low heat release boilers is NOx at 0.1 lb/MMBtu on a 30-day rolling average. For high heat release boilers the NOX limit is 0.2 lb/MMBtu on a 30-day rolling average (see Table 3.4-2). The SO_2 and PM limits apply only to coal- or oil-fired units. The regulation also requires a continuous emission monitoring system (CEMS) and specific recordkeeping and reporting requirements.

Table 3.4-2
NSPS Subpart Db Limits for Auxiliary Boiler

Pollutant	Emission Limit
SO_2	None for natural-gas fired units
PM	None for natural-gas fired units
NOx	0.1 lb/MMBtu* 0.2 lb/MMBtu**

*Low heat release rate boilers
**High heat release rate boilers

3.4.8 Tank Vent Boiler: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (40 C.F.R. Part 60, Subpart Dc)

The Tank Vent Boiler will be covered by NSPS Subpart Dc since it is a steam-generating unit that is less than 100 MMBtu/hr, but greater than 10 MMBtu/hr. Since this unit will burn syngas, it is considered a coal-fired unit for the purposes of this regulation, and the emission limits in Table 3.4-3 apply.

Table 3.4-3
NSPS Subpart Dc Limits for Tank Vent Boiler

Pollutant	Emission Limit	Proposed Emission Limits*
SO_2	0.6 lb/MMBtu**	No change
PM	0.10 lb/MMBtu	0.03 lb/MMBtu
Opacity	20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity	No change

*70 FR 9706
**50% reduction in potential combustion concentration applies.

The regulation also requires CEMS or fuel monitoring for demonstrating SO_2 compliance, and continuous opacity monitors (COMS) for particulate matter/opacity compliance. The regulation also includes specific reporting and recordkeeping requirements.

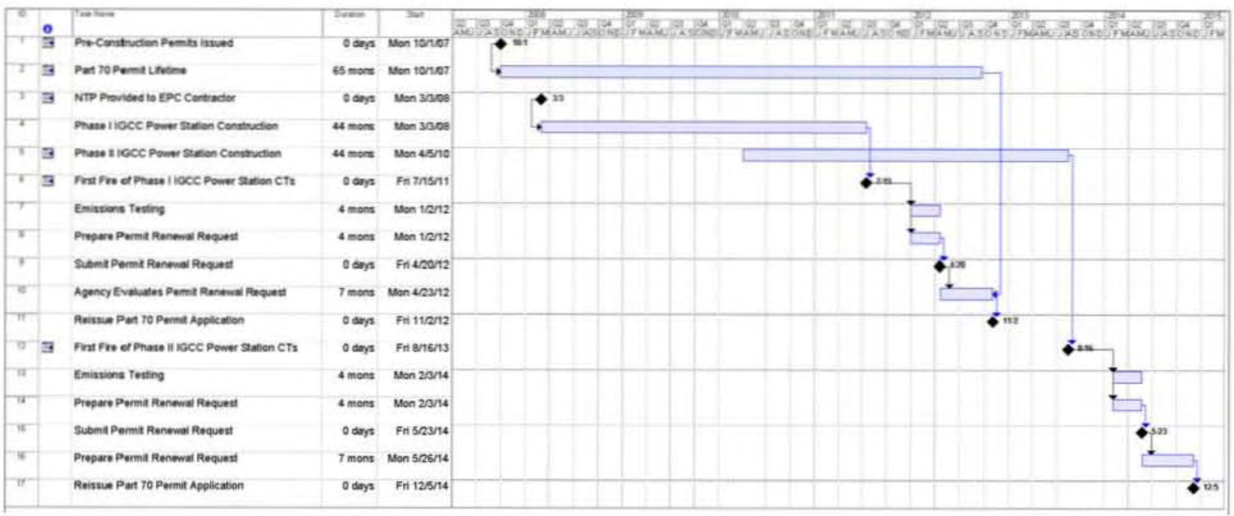
3.5 National Emission Standard for Hazardous Air Pollutants (40 C.F.R. Part 63)

Regulations in 40 C.F.R. Part 63 contain subparts applicable to specific categories of major sources of hazardous air pollutant (“HAP”) emissions and specify that Maximum Achievable Control Technology be applied to such sources (hereafter, the “MACT Standards”). Major sources of HAP emissions are defined as sources with the potential to emit (“PTE”) 10 tons per year (“TPY”) of any individual HAP or 25 TPY of any combination of HAPs. Table 4.2-1 provides evidence that the PTE for HAPs from the Phase I IGCC Power Station will be below the 10 TPY and 25 TPY major source thresholds. Therefore the Phase I IGCC Power Station is not a major source of HAPs as defined under the National Emission Standards for Hazardous Air Pollutants (NESHAP) and is not subject to the MACT Standards thereunder.

Table 4.2-1 shows that the Phase I and II IGCC Power Station has the potential to emit HAPs in a quantity that rounds up to 24 TPY. This PTE equals the major source threshold and, therefore triggers the applicability of the MACT Standards. However, the basis for the HAP emissions estimates presented in Appendix B show such estimates to be extremely conservative (that is, calculated to produce the maximum PTE in the case of every HAP evaluated). The Applicant proposes to confirm the inapplicability of the MACT standards on the Phase I and II IGCC Power Station by testing conducted during operation of the Phase I IGCC Power Station. Such testing would be conducted prior to the submittal of the renewal request for the Part 70 Permit. If testing showed that full load operation of the Phase I and II Power Station would exceed the HAPs major source threshold, the Part 70 Permit could be changed to incorporate the necessary provisions prior to first fire of the Phase II IGCC Power Station. As noted in sections 3.5.1 through 3.5.4 below, the design of the Phase I and II IGCC Power Station will satisfy all emission reduction-related elements of the MACT rules, independent of whether or not the PTE for HAPs emissions from operation of the combined Phase I and II Power Station is shown to be exceeded.

Issuance of the Part 70 Permit for the Phase I and II Power Station is expected by the 2nd quarter of 2007. Therefore, the Applicant would be required to submit 180 days in advance of the Permit's 2nd quarter of 2012 expiration date, an application for the Part 70 Permit's renewal. Such request would contain the results of emissions testing from the Phase I IGCC Power Station. See Figure 3.5-1 to see an overview schedule showing how the emissions testing of the Phase I IGCC Power Station fits into the Part 70 Permit review schedule.

Figure 3.5-1. Part 70 Permit Issuance and Renewal Cycle: Temporal Definition of Emissions Testing of the Phase I IGCC Power Station



Potentially applicable MACT regulations that were reviewed include proposed regulations for Utility MACT, Subpart YYYY (Stationary CTGs), Subpart Q (Industrial Process Cooling Towers) and the requirement for case-by-case MACT. The results of these reviews are presented below.

3.5.1 Utility MACT

In March 2005 at 70 FR 15994, EPA revised a December 2000 appropriate and necessary finding for coal and oil-fired utility units to conclude that is it not appropriate and necessary to regulate coal- and oil-fired utility units under Section 112, and removed these units from the Section 112(c) list.

EPA instead established standards of performance for mercury (Hg) for new and existing coal-fired utility units, as defined in Clean Air Act (CAA) Section 111, pursuant to the CAMR as described in Section 3.4.2 above. The definitions in the new rules, as described in the NSPS sections for Subpart Da and HHHH, include IGCC units as coal-fired units.

In October 2005 at 70 FR 62200, EPA agreed to reconsider certain aspects of its determination that regulation of electric utility steam generating units under section 112 of the Clean Air Act was neither necessary nor appropriate, and removing coal- and oil-fired utility units from the list of source categories. However, EPA declined to issue a stay, and the new rule therefore remains in effect. Pending the outcome of this reconsideration, the IGCC power station is prepared to comply with any new or modified applicable regulations or required analyses.

3.5.2 Combustion Turbine MACT

On March 5, 2004, EPA published the final NESHAP for Stationary CTGs at 69 FR 10511. The rule applies to owners/operators of stationary CTGs located at a major source of HAP emissions. The final rule included eight subcategories within the Stationary CTG source category:

(1) Emergency Stationary CTGs.
(2) Stationary CTGs, which burn landfill or digester gas equivalent to 10% or more of the gross heat input.
(3) Stationary CTGs <1 MW peak power output.
(4) Lean premix gas-fired CTGs.
(5) Lean premix oil-fired CTGs.
(6) Diffusion flame gas-fired CTGs.
(7) Diffusion flame oil-fired CTGs.
(8) CTGs operated on the North Slope of Alaska.

On August 18, 2004, the EPA issued a final stay of the above provisions for lean premix gas-fired turbines and diffusion flame gas-fired combustion turbines, pending the outcome of the EPA's proposal to delete these subcategories from the source category list. On April 7, 2004, the EPA noticed its intention to delete four subcategories from the Stationary CTGs source category that was developed pursuant to CAA Section 112(c)(1).

Therefore, compliance with this rule is currently not required for the proposed diffusion flame gas-fired CTGs. In addition, during the proposals for the Utility NSPS, CAMR, and CTG NSPS, it became clear that EPA's intention was to regulate IGCCs with coal-fired utility units, rather than CTGs (see Section 3.4.3).

3.5.3 Case-by-Case MACT

Subsection 112(g)(2)(B) of the CAA provides:

> After the effective date of a permit program under Title V in any state, no person may construct any major source of hazardous air pollutants, unless the Administrator (or the State) determines that the maximum achievable control technology emission limitation under this section for new sources will be met. Such determination shall be made on a case-by-case basis where the Administrator has established no applicable emission limitations.

EPA promulgated regulations implementing this section at 40 C.F.R. Part 63, Subpart B. Provisions at 40 C.F.R. 63.40(b) provide that the requirements of sections 63.40 through 63.44 apply to any major source of HAPs constructed after the effective date of Section 112(g)(2)(B) and the effective date of a state's Title V operating permit program, unless the source has been specifically regulated or exempted from regulation under Section 112.

EPA's action to delist coal- and oil-fired utility units (70 FR 15994, March 29, 2005) represents its conclusion that HAP emissions remaining from coal- and oil-fired utility units after the implementation of the other requirements of the CAA do not cause hazards to public health that would warrant regulation under CAA Section 112. The HAP of greatest concern from coal-fired utility units is mercury (EPA, 70 FR 28609). Therefore, in conjunction with the action described above, the EPA established the CAMR for mercury under Section 111 of the CAA for new and existing sources, which integrated mercury limits into the Utility NSPS rules at 40 C.F.R. 60 Subpart Da.

In addition, as described above, on April 7, 2004, EPA noticed its intention to delete four subcategories from the Stationary CTGs source category that were developed pursuant to CAA Section 112(c)(1).

Therefore, case-by-case MACT is not required for new IGCC facilities since coal-fired utility units and diffusion flame gas-fired turbines have been removed or proposed for removal from the Section 112(c) source category list.

In response to two petitions (one from a coalition of states and the other from five environmental groups and four Indian Tribes), EPA reconsidered portions of the CAMR and the removal of coal-fired utility units from the section 112(c) list. On May 31, 2006, EPA took final action on these petitions reaffirming its determination that regulation of electric utility steam generating units under Section 112 of the CAA was neither necessary nor appropriate.

3.5.4 Industrial Process Cooling Towers (Subpart Q)

Subpart Q is applicable to cooling towers that use chromium-based treatment chemicals. The cooling towers proposed to be used at the IGCC Power Station will not use chromium-based treatment chemicals and are therefore not subject to this regulation.

3.6 Acid Rain Program (40 C.F.R. Parts 72-78)

Pursuant to Title IV of the 1990 CAA Amendments, the EPA established a program to control emissions that contribute to the formation of acid rain. The acid rain regulations, codified under 40 C.F.R. Parts 72, 75 and 76 are applicable to "affected units" as defined in the regulations. As a new utility unit, the IGCC Power Station is classified as an affected unit under 40 C.F.R. 72.6(a)(3), and is therefore subject to the Acid Rain Program.

Owners or operators of an affected unit are subject to the following Acid Rain Program requirements:

- Acid Rain Permit Application.
- SO_2 emission allowances.
- NO_x emission limitations.

- Acid Rain Compliance Plan.
- Emission monitoring requirements.

For new units, an Acid Rain Permit application must be submitted at least 24 months prior to the date of initial operation of the unit. The application must demonstrate compliance with the Acid Rain Program requirements and include a complete compliance and monitoring plan.

3.6.1 Part 72 Permit Regulation

All utility generating units greater than 25 MW are required to obtain a Phase II Acid Rain Permit. This permit is generally incorporated into a facility's Title V Operating Permit and is issued by the state. In order to comply with the requirements of 40 C.F.R. Part 72, the following course of action will be taken by Excelsior:

- The IGCC Power Station will obtain an ORIS code from the U.S. Department of Energy (DOE).
- The Applicant will submit a request letter to the EPA and DOE to issue a public notice identifying a designated representative for the proposed project, as stipulated in 40 C.F.R. 72.20 (Authorization and Responsibilities of the Designated Representative) and 72.24 (Certification).
- A Phase II Acid Rain Permit Application will be submitted at a later date in order to allow a permit to be issued prior to the start of operation of the proposed IGCC Power Station.

3.6.2 Part 73 – Sulfur Dioxide Allowance System

Part 73 of the Acid Rain provisions establishes requirements related to a SO_2 allowance system. These requirements include:

- The allocation of SO_2 emission allowances.
- The tracking, holding and transfer of allowances.
- The deduction of allowances for purposes of compliance.
- Miscellaneous other requirements.

The Applicant is aware of the requirements to secure SO_2 allowances on an annual basis and will comply with the appropriate requirements.

3.6.3 Part 75 Continuous Emission Monitoring

Affected units are also required by 40 C.F.R. Part 75 to continuously monitor emissions of SO_2 and NO_x. In addition, the EPA is requiring affected units to monitor emissions of carbon dioxide (CO_2) and opacity. Generally, this would require the installation of Continuous Emission Monitoring Systems (CEMS). However, several exemptions exist in these regulations that apply to gas-fired units. The IGCC units are considered gas-fired for the purposes of this regulation since the definition of "coal-fired" at 40 C.F.R. 72.2 specifically excludes coal-derived gaseous fuel that meets the definition of "very low sulfur fuel" (either < 0.05 percent sulfur by weight or < 20 grains sulfur per 100 scf). The sulfur concentration in the undiluted syngas produced by the IGCC Power Station's clean up system will be less than or equal to 50 ppmvd hydrogen sulfide on a rolling 30-day average, which is equivalent to approximately 6 grains of sulfur per 100 scf. Therefore, the IGCC Power Station will be considered gas-fired for purposes of the Acid Rain Program. As a general note, the following items apply to gas-fired units:

- Gas-fired units are exempt from opacity monitoring (40 C.F.R. 75.14(c)).
- Gas-fired units can monitor SO_2 according to the protocol of Appendix D in lieu of a SO_2 CEMS and flow monitoring (40 C.F.R. 75.11 (d)(2)). If the fuel is pipeline quality natural gas, an emission factor of 0.0023 lbs SO_2/MMBtu is used in combination with hourly metered gas usage.
- Gas-fired units can monitor CO_2 according to the protocol of Appendix G in lieu of a CO_2 CEMS and flow monitoring (Section 2.3 of Appendix G of 40 C.F.R. 75). The protocol involves use of an emission factor in combination with calculated hourly heat input.
- Gas-fired units are not exempt from the CEMS requirements unless the units are considered peaking units (less than 20% operation of the nameplate capacity and an average operating factor of 10% over a three-year period).
- According to 40 C.F.R. 75.10(c), the owner or operator shall determine and record the heat input to each affected unit for every hour when fuel is combusted, following the procedures in Appendix F of 40 C.F.R. Part 75.

The Applicant is aware of these requirements and will develop appropriate procedures to comply with the requirements of 40 C.F.R. Part 73 and 75.

3.7 Clean Air Interstate Rule Permit

The final Clean Air Interstate Rule ("Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone [Clean Air Interstate Rule]; Revisions to Acid Rain Program; Revisions to NOx SIP Call; Final Rule") hereafter termed "CAIR," was published in the Federal Register on May 12, 2005 at 70 FR 25162. In August through December 2005, EPA received multiple petitions for reconsideration of various specific portions of the rule. EPA expects to take final action on all issues under reconsideration by March 15, 2006. By that date, EPA would finalize the process of reconsideration by issuing a final rule or proposing a new approach. EPA also expects, by March 15, 2006, to issue decisions on all remaining issues raised in the petitions for reconsideration, including whether or not Minnesota should be included in the CAIR region.

On March 15, 2006, the EPA resolved its issues relating to CAIR and on April 28, 2006 published in the Federal Register its conclusions that reconsideration of CAIR is not warranted under section 307(d)(7)(B) of the CAA and rejected the request to stay implementation of CAIR in Minnesota.

In accordance with 40 C.F.R. 96.121, Excelsior's designated representative will submit a CAIR Permit application at least 18 months before the IGCC Power Station commences operation, such application to include the standard requirements specified at §96.106, as amended.

3.8 Compliance Assurance Monitoring (40 C.F.R. Part 64)

The proposed equipment will not be equipped with add-on air pollution control devices, and therefore Compliance Assurance Monitoring (CAM), as specified in 40 C.F.R. Part 64, will not be required for the project. In addition, the monitoring requirements specified under the Acid Rain Provisions and the applicable NSPS will be sufficient to qualify for exemption under the CAM requirements in 40 C.F.R. 64.2(b).

3.9 Chemical Accident Provisions (40 C.F.R. Part 68)

This regulation applies to stationary sources that will have more than a threshold quantity of the specific regulated toxic and flammable chemicals. The intent of these regulations, as required by section 112(r) of the CAA Amendments, is to prevent accidental releases to the air and mitigate the consequences of any such releases by focusing prevention measures on chemicals that pose the greatest risk to the public and the environment. EPA promulgated a list of 140 regulated substances, with threshold quantities, that is used to define the stationary sources that will be subject to accident prevention regulations mandated by section 112(r)(7) on January 31, 1994 (59 FR 4478). On June 20, 1996, EPA promulgated the full risk management program (RMP) rules for accident prevention (61 FR 31668), which have been incorporated into the Code of Federal Regulations as 40 C.F.R. 68.

Stationary sources covered by this regulation must develop and implement a risk management program that includes a hazard assessment, a prevention program, and an emergency response program. These elements are to be described in a risk management plan that must be submitted to EPA and state and local emergency planning authorities. The plan must also be made available to the public by the date that a regulated substance is first present in a process above a threshold quantity.

The IGCC Power Station is not expected to have any chemicals above the threshold amounts. The Applicant will perform more detailed calculations as the system design is finalized, and will comply will all applicable provisions of the regulation in a timely manner.

3.10 State of Minnesota Requirements

3.10.1 Minnesota Air Pollution Episodes (Minn. R. 7009.1000-.1110)

Since the IGCC Power Station will have allowable emissions of greater than 250 tons per year of any single regulated pollutant, the plant is subject to Minnesota's Air Pollution Episode rules. The rules require preparation of an emergency action plan to be implemented in the event that the Commissioner of the MPCA makes an air pollution episode declaration.

3.10.2 Minnesota Standards of Performance for Stationary Sources (Minn. R Ch. 7011)

3.10.2.1 Control of Fugitive Particulate Matter (Minn. R. 7011.0150)

Bulk material handling operations at the IGCC Power Station including coal, petroleum coke, flux and other materials are subject to Minnesota's fugitive dust control rule, Minn. R. 7011.0150. The rule prohibits the release of "avoidable amounts" of particulate matter. Subject facilities are required to take reasonable precautions to prevent the discharge of visible fugitive emissions beyond the property line.

3.10.2.2 Standards of Performance for New Indirect Heating Equipment (Minn. R. 7011.0515)

The IGCC Power Station will use the following indirect heating equipment: CTGs, tank vent boilers and auxiliary boilers. However, these units will not be subject to Minn. Rules 7011.0515 because they will be subject to federal NSPS (40 C.F.R. 60 subparts Da, Db and Dc). New units subject to the federal standards are exempt from the state standards pursuant Minn. R. 7011.0505, subp. 1.

3.10.2.3 Standards of Performance for Coal Handling Facilities (Minn. Rules 7011.1100-7011.1140)

The only provision of the Standards of Performance for Coal Handling Facilities applicable to IGCC Power Station is the requirement to avoid any nonessential coal handling operations that are not shielded from the wind when steady wind speeds exceed 30 miles per hour (Minn. R. 7011.1125). Since the IGCC Power Station would not be located in the Minneapolis/St. Paul area or the City of Duluth, would not be an existing out-state coal handling facility, and would not operate pneumatic coal-cleaning equipment or thermal dryers, the other provisions of the Standard do not apply. For new coal preparation plants, the Federal NSPS at 40 C.F.R. Part 60, Subpart Y apply.

3.10.2.4 Standards of Performance for Stationary Internal Combustion Engines (Minn. R. 7011.2300)

The IGCC Power Station will occasionally operate the following internal combustion engines that are subject to this rule: emergency fire water pumps and the emergency generators. The rule limits visible emissions from these units to 20 percent opacity and limits SO_2 emissions to 0.5 lb/MMBTU heat input unless a higher limit has been established through modeling.

3.10.2.5 Standards of Performance for Post-1969 Industrial Process Equipment (Minn. R. 7011.0715)

The IGCC Power Station will operate coal, petroleum coke, and slag handling equipment that will generate particulate matter emissions. This equipment will be subject to the Standards of Performance for Post-1969 Industrial Process Equipment. Subject equipment must meet either the numeric PM emission limit calculated using one of the two formulas shown in Table 3.10-1 or use pollution control equipment that achieves the required control efficiency. Since the IGCC Power Station is located outside of Minneapolis, St. Paul and Duluth, and is located more than one quarter mile from any residence or public roadway, the required control equipment efficiency standard to be applied is 85 percent.

Table 3.10-1
Particulate Matter Emission Limit for Process Equipment

PM Emission Limit for equipment that process less than 30 tons/hour	**PM Emission Limit** for equipment that process greater than 30 tons/hour
$E = 3.59\ P^{0.62}$ Where: E = Emission Limit in lbs/hr P = Process Weight in tons/hour	$E = 17.31\ P^{0.16}$ Where: E = Emission Limit in lbs/hr P = Process Weight in tons/hour

This standard also limits emissions from subject equipment to less than 20 percent opacity.

3.10.3 Minnesota Acid Deposition Control (Minn. R. Ch. 7021)

This regulation applies to existing electrical generating facilities that have a total capacity greater than 1,000 megawatts. As Mesaba One and Mesaba Two will be new generating facilities, this provision does not apply. However, the Applicant will be required under the Federal Acid Rain Program to annually purchase SO2 allowances in an amount equal to the total IGCC Power Station annual SO2 emissions. The Federal Acid Rain Program will be superseded by the CAIR when the new rule becomes effective. Pursuant to Minnesota regulations, Excelsior's compliance with the new Federal rule also constitutes compliance with the Minnesota requirements.

The IGCC Power Station would also be subject to the Reasonable Available Control Technology (RACT) requirements of Minn. R. 7021.0050, Subpart 5 because the total indirect heating capacity of the CTGs, tank vent boilers, and auxiliary boilers exceed 5,000 MMBTU/hr. However, since emissions from these units are subject to BACT requirements, no additional limitations are necessary to meet RACT.

4. AIR EMISSIONS INVENTORY

Air emission points are shown on Figure 1.6-5 and in the block flow diagrams presented in Figures 2.3-1 and 2.3-2. The emission unit ("EU") and stack/vent ("SV") identification numbers correspond to those used on the forms provided in Section 9.

The IGCC Power Station will be designed to process a relatively wide variety of feedstocks, including sub-bituminous coal, bituminous coal and petroleum coke. Plant performance will vary depending on a number of factors, including the feedstocks utilized, combustion turbine operating mode, gasifier operating requirements/parameters, and ambient conditions. Table 2.6-1 presents the currently estimated range of key plant performance characteristics expected for each phase of the IGCC Power Station while operating in the PSQ mode.

Maximum and average emission quantities from the IGCC Power Station have been estimated by using:

- Plant performance characteristics identified in Table 2.6-1.
- Equipment supplier data.
- BACT as proposed in this application.
- Test results for similar equipment at other IGCC facilities, especially the existing Wabash River Coal Gasification Repowering Project (an operating IGCC power station that uses E-Gas™ gasification technology; hereafter referred to as "Wabash River").
- Engineering calculations, experience, and judgment.
- Published and accepted average emission factors, such as the U.S. EPA Compilation of Air Pollutant Emission Factors (AP-42).

The following sections describe these estimates and the calculation basis for both criteria and non-criteria pollutants. Detailed calculation descriptions and examples are presented in Appendix A (criteria pollutant emissions) and Appendix B (hazardous air pollutant emissions).

4.1 Criteria Pollutants

Table 4.1-1 presents the normal and maximum short-term emission rates for each source. Table 4.1-2 shows the proposed maximum annual criteria pollutant emission rates for each emission source in the facility.

Table 4.1-1
Short-Term Emission Summary (Phase I and II)

Emission Source	Normal Emission Rate (lb/hr)[1]					Maximum Emission Rate (lb/hr)[1]				
	NOx	SO_2	CO	PM10[2]	VOC	NOx	SO_2	CO	PM10[2]	VOC
Combustion Turbines	624	270	380	100	35	792	732	10,960[3]	100	1,052[3]
Tank Vent Boilers	12	7.2	3.6	0.4	0.2	39	17	12	1.4	0.6
Flares[4]	0.3	negl[5]	2.2	negl	negl	478	2,080	11,400	60	45
Auxiliary Boilers	9.4	0.8	19	1.3	1	9.4	0.74	19	1.3	1
Cooling Towers				9					9	
Fugitive PM10				8.6					8.6	
Fugitive VOC					3.8					3.8
Emergency Generators	158	4.1	36	5.8	6.1	158	4.1	36	5.8	6.1
Emergency Fire Water Pump Engines	37	2.5	8.0	2.6	3.0	37	2.5	8.0	2.6	3.0
Total	**841**	**285**	**449**	**128**	**49**	**1,513**	**2,836**	**22,435**	**189**	**1,112**

[1]See following text for description of normal and maximum short-term emissions.
[2]PM10 includes filterable plus condensable fractions.
[3]Peak startup emission rate for four CTGs; normally startup for these engines will not occur simultaneously.
[4]Normal flare emission rates are for natural gas pilots only.
[5] negl = negligible emissions.

Table 4.1-2
Annual Emission Summary (Phase I and II)

Emission Source	Emission Rate (ton/year)				
	NOx	SO_2	CO	PM10	VOC
Combustion Turbines	2,772	1,332	1,928	440	176
Tank Vent Boilers	53	32	16	1.8	0.8
Flares	27	25	572	3.4	2.6
Auxiliary Boilers	10	0.8	21	1.4	1.2
Cooling Towers				39	
Fugitive PM10				6.7	
Fugitive VOC					17
Emergency Generators	7.9	0.2	1.8	0.29	0.31
Emergency Fire Water Pump Engines	1.9	0.12	0.40	0.13	0.15
Total	**2,872**	**1,390**	**2,539**	**493**	**197**

(See following text for explanation of annual emission basis.)

4.1.1 Combustion Turbine Generators

Emissions from the power block CTGs are primarily controlled through the inherently lower polluting IGCC coal gasification technology. Specifically, the production of syngas at relatively high pressure permits efficient and cost-effective syngas cleanup prior to combustion in the CTGs to produce electricity. As discussed in the preceding process description in Section 2.3, the following treatment steps will be applied to the syngas:

- Hot gas particulate matter filtration via cyclone and ceramic filters to achieve approximately 99.9% particulate matter removal.
- Water scrubbing to remove soluble contaminants, condensable materials, and suspended particulate matter.
- Amine treatment combined with COS hydrolysis to reduce total syngas sulfur to a maximum of 50 ppmvd as H_2S in the undiluted syngas, rolling 30-day average.
- Carbon adsorption for removal of mercury and other trace contaminants.
- Moisturization (water saturation) for NOx control and improved power production.

In addition to these syngas treatment measures, the moisturized syngas fuel is diluted by about 100 percent (one-to-one) with ASU nitrogen for additional NOx reduction. Steam injection, in lieu of nitrogen dilution and moisturization, will be used for NOx control when operating on natural gas. Finally, each CTG will be equipped with inlet air filters to minimize particulate matter emissions potentially caused by advection of suspended atmospheric materials contained in the combustion air.

The following CTG emission rates are proposed as BACT and are used for project emission estimates:

Syngas

- SO_2, based on 50 ppmvd as hydrogen sulfide in the undiluted syngas, rolling 30-day average.
- NOx, 15 ppmvd (@ 15% O_2).
- CO, 15 ppmvd (@ 15% O_2).
- PM_{10}, 25 lb/hr/CTG.
- VOC, 2.4 ppmvd (@15% O_2).

Natural Gas

- SO_2, pipeline-quality natural gas (assumed 1.0 grain/100 scf total sulfur).
- NOx, 25 ppmvd (@ 15% O_2).
- Other criteria pollutants, equal to or less than syngas emission rates.

As is the case with many types of internal combustion engines, CTG emissions of one or more pollutants during startup can exceed the normal operating emission rates for short periods. This temporary higher emission rate is caused by reduced combustion efficiencies during initial operation at low temperatures and low loads, as well as delay in achieving minimum specified combustor conditions to begin steam injection for NOx control.

Table 4.1-3 shows the maximum short-term CTG emission rates for the four principal operating conditions. Since a specific CTG supplier has not yet been selected, the emission rates shown in this table reflect the maximum values for potentially available commercial CTGs.

Table 4.1-3
Maximum CTG Short-Term Emission Rates (Phase I and II)

Operating Mode	Emission Rate (lb/hr)				
	NO_X	SO_2	CO	PM_{10}	VOC
Normal syngas operation[1]	624	270	380	100	35
Maximum syngas operation[2]	624	732	380	100	35
Maximum natural gas operation	792	24	288	72	26
Worst-case startup[3]	484	<24	10,960	44	1052

[1]30-day rolling average fuel sulfur
[2]Peak 1-hour average fuel sulfur
[3]Worst-case startup for four CTGs; normally all four would not start up simultaneously

The maximum annual CTG emission rates and basis are summarized in Tables 4.1-4 and 4.1-5 for the first four years of operation and years 5-30, respectively:

Table 4.1-4
Maximum CTG Annual Emissions Years 1-4 (Phase I and II)

	YEAR NO. 1 TONS/YEAR	YEAR NO. 2 TONS/YEAR	YEAR NO. 3 TONS/YEAR	YEAR NO. 4 TONS/YEAR	BASIS[1]
Hrs/Yr	2630	1750	880	440	Peak natural gas per year
NO_x	2954	2880	2807	2770	Balance of year on syngas at full load
SO_2	964	1088	1210	1271	Balance of year on syngas at full load, 50 ppm annual average sulfur in fuel
CO	1808	1848	1888	1909	Plus 50 hr/yr startup/shutdown, balance of year on syn gas at full load
PM_{10}	401	414	426	432	Balance of year on syn gas at full load
VOC	167	171	174	176	Plus 50 hr/yr startup/shutdown, balance of year on syn gas at full load

[1] Indicated hours of natural gas full load operation plus additional operation described for each pollutant.

Table 4.1-5
Maximum CTG Annual Emissions Years 5-30 (Phase I and II)

	TONS/YEAR	BASIS
NO_x	2,772	440 hours (approx 5% of the year) on full-load natural gas operation; 8,320 hours on full load syngas operation.
SO_2	1,332	Full year (8,760 hours) on full-load syngas operation; 50 ppmv average total sulfur in syngas.
CO	1,928	50 hours startup/shutdown per CTG, balance of year (8,710 hours per CTG) on full-load syngas operation
PM_{10}	440	Full year (8,760 hours) on full load syngas operation
VOC	176	50 hours startup/shutdown per CTG, balance of year (8, 710 hours per CTG) on full load syngas operation

4.1.2 Tank Vent Boilers

The tank vent boilers (TVBs, one for each phase) will be designed to safely and efficiently dispose of recovered process vapors from various process tanks and vessels associated with the gasification process. The TVBs prevent the atmospheric emission of reduced sulfur compounds and other gaseous constituents to the atmosphere that could cause nuisance odors and other undesirable environmental consequences. The TVBs may also be operated on natural gas to produce steam for the IGCC Power Station during gasifier shutdowns. The estimated maximum short-term and annual emission rates, based on supplier estimates for similar equipment, are shown in Table 4.1-6 and Table 4.1-7, respectively.

Table 4.1-6
Tank Vent Boiler Short-Term Emissions (Phase I and II)

Operating Mode	Emission Rate (lb/hr)				
	NO_x	SO_2	CO	PM_{10}	VOC
Normal syngas operation[1]	9	7	2.6	0.3	0.1
Maximum syngas operation[2]	39	17	12	1.4	0.6
Maximum natural gas operation[3]	24	0.2	7.2	0.8	0.3

[1]Assumes 30 mmBtu/hour heat input rate
[2]Assumes 130 mmBtu/hour heat input rate
[3]Assumes 80 MMBtu/hour heat input rate

Table 4.1-7
Maximum Tank Vent Boiler Annual Emissions* (Phase I and II)

	tons/year
NOx	52
SO_2	32
CO	16
PM_{10}	1.8
VOC	0.8

*Based on approximately 280 billion (10^9) Btu/yr syngas plus tank vent vapors, and about 73 billion Btu/yr natural gas combusted. Assumed sulfur in tank vapors averages 1.5 lb/hr (each phase) on annual basis.

4.1.3 Flares

The elevated flares for each project phase will designed for a minimum 99 percent destruction efficiency of carbon monoxide and hydrogen sulfide. As discussed previously, the flares are normally used only to oxidize treated syngas and natural gas combustion products during gasifier startup operations. The flares will also be available to safely dispose of emergency releases from the IGCC Power Station during unplanned upset events.

The estimated maximum short-term and annual emission rates, based on agency guidance and supplier advice, are shown in Table 4.1-8.

Table 4.1-8
Flare Emission Rates (Phase I and II)

Operating Mode	Emission Rate (Lb/Hr)				
	NO_x	SO_2	CO	PM_{10}	VOC
Normal Operation[1]	0.3	0.01	2.2	0.03	.02
Normal Startup Operation[2]	230	370	5,350	28	21
Maximum Flaring Operation[3]	480	2,080	11,400	60	45
	Emission Rate (Tons/Year)				
Maximum Annual[4]	26.8	24.6	572	3.4	2.6

[1]Natural gas pilot, only.
[2]Startup flaring of syngas for two gasifiers and two flares – may occur for several days per event, but not normally for two gasifiers simultaneously.
[3]Maximum flaring capacity for two flares, based on flaring syngas production from two gasifiers for each flare and a worst case upset sulfur content of 400 ppmv in syngas - one hour or less per event.
[4] Maximum annual emission based on combustion of approximately 700 billion Btu of syngas and 136 billion Btu of natural gas during startup, plant upsets, and normal operating conditions – see Appendix A, Exhibit A-2 for assumed worst case annual flaring scenarios and durations.

4.1.4 Fugitive Equipment Leaks

VOC and HAPs emissions associated with normal equipment leakage have been estimated using standard U.S EPA fugitive emissions factors for valve seals, pump and compressor seals, pressure relief valves, flanges, and similar equipment. Most of the estimated VOC emissions are associated with the amine handling system since methyl diethanolamine (MDEA) would be the only VOC handled in relatively significant quantity at the facility. Fugitive emission estimates of HAPs are based on the estimated concentration of each HAP in various syngas streams multiplied by the calculated total leakage rates of process fluid. Fugitive emission estimates for individual HAPs are shown in Table 4.1-9.

Table 4.1-9
Fugitive Emission Estimate (Phase I and II)

Emission Type	Emission Rate	
	lb/hr	ton/yr
Federal HAPs	0.06	0.3
Ammonia	0.2	1.3
Hydrogen sulfide	4.0	17
MDEA	3.2	14
VOC	3.8	16
TRS	4.0	17

[1]Volatile organic compounds (VOC) include MDEA, benzene, carbon disulfide, carbonyl sulfide, ethyl benzene, hexane, hydrogen cyanide, naphthalene, toluene, xylenes, and waste oil,
[2]Total reduced sulfur (TRS) includes carbon disulfide, carbonyl sulfide, and hydrogen sulfide.

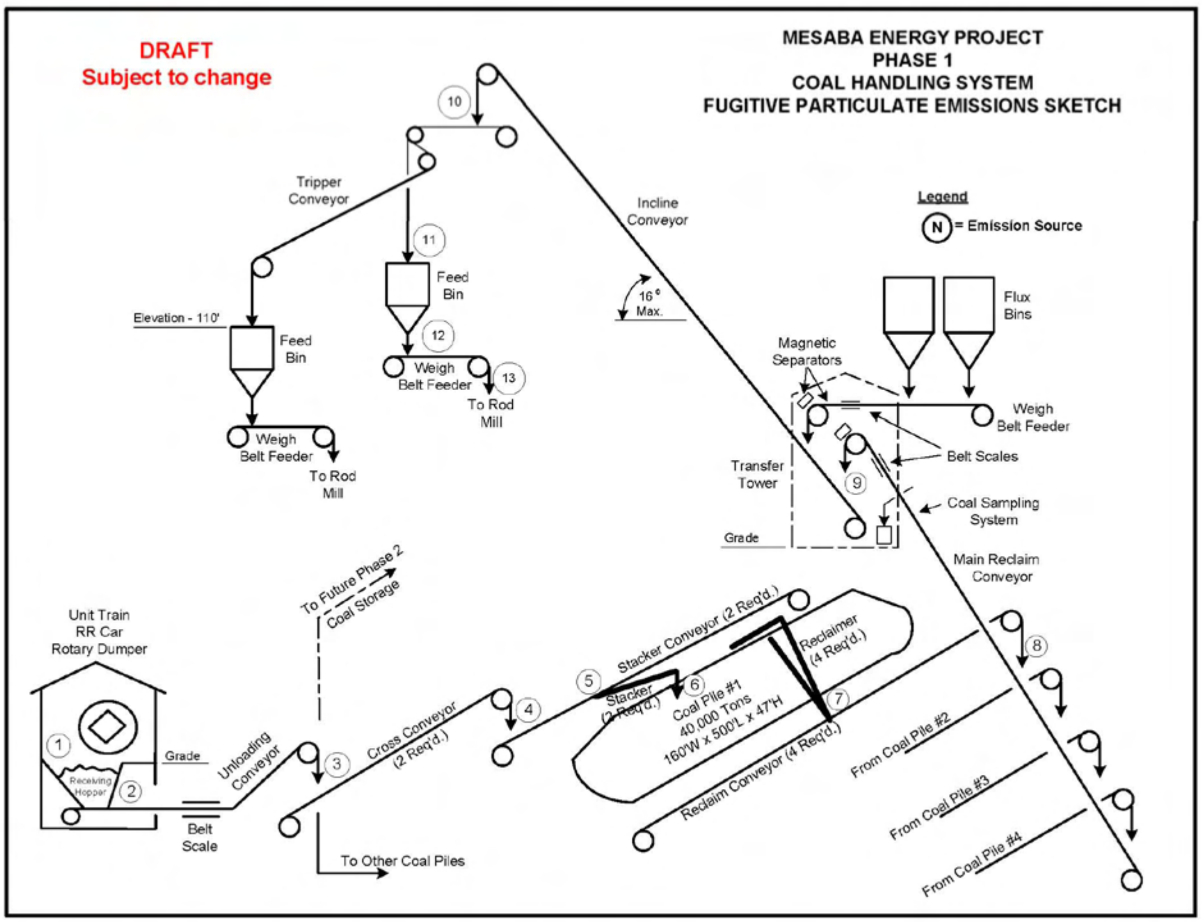
4.1.5 Material Handling Systems

Fugitive particulate matter emissions (fugitive dust) will be generated by coal/coke, flux, slag handling, fuel preparation, and fuel storage during the normal operation of the IGCC Power Station. Sources of these emissions include the active and inactive coal/coke storage piles, conveyors/transfer points, slurry preparation area, and the slag storage area. Estimated emissions of total suspended particulate matter (particulate matter with an aerodynamic diameter no greater than 30 microns) and PM_{10} (particulate matter with an aerodynamic diameter no greater than 10 microns) for these sources are summarized in Table 4.1-10 for Phase I operations (fugitive particulate matter emission rates for Phase I and II would be twice the values shown.). Detailed calculations are presented in Appendix A, Exhibit A-5.

The estimates of particulate matter emission rates (lb/hr, tons/year) are based on methodologies developed by the U.S. EPA and documented in AP-42 ("Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources", 5th Edition). Specific portions of AP-42 utilized in the current analysis include Section 13.2.4 (Aggregate Handling and Storage Piles), Section 13.2.5 (Industrial Wind Erosion), and Section 13.2.2 (Unpaved Roads). These sections were used to estimate emission factors for the various coal/slag handling and moving components, windage losses from the coal and slag piles, and emissions resulting from (on-site) truck traffic movement of slag from process units to the slag storage pile.

The emission factor for rail car unloading of feedstock was developed from the Electric Power Research Institute (EPRI) report CS-3455, published in June 1984. The peak hourly throughput for this system, as well as for conveyors and transfer points up to the storage pile, is based upon unloading approximately 36 unit train cars per hour (approximately 4,300 tons/hr). Figure 4.1-1 shows a sketch of the proposed feedstock handling system.

Figure 4.1-1
Material Handling System for Phase I IGCC Power Station



The emission factors (expressed in lb/ton) for aggregate handling systems derived from AP-42 are multiplied by the maximum material throughput to estimate an uncontrolled particulate matter emission rate. Peak values are expressed on an hourly basis and represent the maximum system throughput requirements. For the materials handling facilities upstream of the coal pile, this rate is as described above. For materials handling facilities downstream of the storage pile, the peak rate is based upon 120% of the average rate required for the nominal plant output. The annual throughput is based on the average material throughput requirement for the plant at full load conditions of 8,760 hours per year. The AP-42 methodology correlates the aggregate handling particulate matter emission factor inversely with coal moisture content. Because of this, the maximum plant fugitive particulate matter emission rates were found to be higher on operation with Illinois No. 6 coal vs. the significantly higher moisture content (and higher as-received throughput rate) for PRB-1 coal. The maximum slag generation and throughput rates are also based on operation with Illinois No. 6 coal. The slightly higher slag generation rate associated with use of a blended coal had an insignificant impact on the emissions from the slag handling systems. However, in practice, PRB coal is known to be dusty. To account for this experience, the surface moisture content in PRB coal was assumed to be 4% and the fugitive particulate matter emission rates were recalculated. The fugitive emissions from PRB coal using the revised assumptions are provided in Table 4.1-10.

The uncontrolled particulate matter emissions estimates are modified as appropriate by a control efficiency multiplier. Control efficiencies used in these estimates include:

1.	No control method	0%
2.	Railcar/Feedstock storage pile load-in	50%
3.	Partial enclosure of transfer point	70%
	3a. Partial enclosure w/dust suppression spray	75%
4.	Full enclosure of transfer point	90%
	4a. Full enclosure w/dust suppression spray	95%
	4b. Full enclosure with baghouse filter	99%
5.	Roadway w/watering and cleaning	80%

The control efficiency for railcar unloading and storage pile load-in using an adjustable stacker are based upon engineering judgment for the partial containment systems planned. References to items 3 and 4 are identified in EPA 450/3-81-005b (Sept. 1982) and Environmental Progress (Feb. 1984). The control efficiencies for items 3a, 4a, and 4b are based upon engineering judgment and preliminary discussions with dust suppression system vendors. Reference to item 5 is found in AP-42 (Section 13.2.2).

The wet spray dust suppression systems will require that water be supplied to the various injection points. This water may be blended with glycol (for freeze point suppression) and/or surfactants (wetting agents) or chemical binding or encrusting agents. Because of the glycol addition, any free water draining from the solids will be captured and treated as required before re-use on-site or off-site disposal.

Determination of particulate matter emissions resulting from wind erosion of the storage piles requires information on pile geometry and wind velocities at the plant site. Oval storage piles have been assumed and lengths, widths, angles of repose and heights have been determined to provide the required storage volumes in one or more piles. These values were used to estimate the pile surface areas exposed to winds, as required by the AP-42 procedure. Historical wind velocity profiles (speed and annual frequency of occurrence) were obtained from University of Minnesota Technical Bulletin AD-TB1955 for the local Hibbing, Minnesota area. The reported wind velocities are relatively low, and only infrequently exceed the threshold friction velocity needed to generate quantifiable emissions as defined by the AP-42 procedure. Hence, at these conditions, the piles were not significant contributors to overall plant particulate matter emissions.

In-plant trucks will be used to transport dewatered, by-product slag from the gasifier slag handling area to the slag storage pile or bins to await shipment by rail or truck offsite. A truck traffic emission factor from AP-42 was used to estimate fugitive road dust from this internal slag transfer operation. A control efficiency of 80% has been applied to this emission source based on watering of the roadway near the pile to suppress dust and periodic removal/cleanup of dust-producing material.

Table 4.1-10. Fugitive Particulate Emission Estimate (Phase I Operation)

Emission Source Description		Notes	PM30 Emission Factor (lb/ton)	PM10 Emission Factor (lb/ton)	Maximum Hourly Throughput (ton/hr)	Maximum Annual Throughput (ton/yr)	Control Method	Control Efficiency (%)	Controlled PM30 Maximum Hourly Emission Rate (lb/hr)	ControlledPM 30 Maximum Annual Emission Rate (ton/yr)	Controlled PM10 Maximum Hourly Emission Rate (lb/hr)	Controlled PM10 Maximum Annual Emission Rate (ton/yr)
COAL HANDLING AND STORAGE												
1	Railcar Unloading	1,9	0.00174	0.00087	4,300	3,100,000	Partially Enclosed Shed with dust suppression sprays	75	1.871	0.674	0.935	0.337
2	Unloading hopper to Unloading Conveyor	2,9	0.0020	0.0010	4,300	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.432	0.156	0.204	0.074
3	Unloading conveyor to Cross-Conveyor	2,9	0.0020	0.0010	4,300	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.432	0.156	0.204	0.074
4	Cross-Conveyor to Stacker Conveyor	2,9	0.0020	0.0010	4,300	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.432	0.156	0.204	0.074
5	Stacker Conveyor to Stacker	2,9	0.0020	0.0010	4,300	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.432	0.156	0.204	0.074
6	Stacker to Coal Pile	2,9	0.0020	0.0010	4,300	3,100,000	Ring-type dust suppression sprays at discharge point; Adjustable height stacker	50	4.323	1.558	2.044	0.737
7	Reclaimer to Reclaim Conveyor	2,8	0.0020	0.0010	430	3,100,000	Partially Enclosed transfer point with dust suppression sprays	75	0.216	0.779	0.102	0.368
8	Reclaim Conveyor to Main Conveyor	2,8	0.0020	0.0010	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.043	0.156	0.020	0.074
9	Main Conveyor to Incline Conveyor	2,8	0.0020	0.0010	430	3,100,000	Fully enclosed transfer point with dust suppression sprays inside building	95	0.043	0.156	0.020	0.074
10	Incline Conveyor to Tripper Conveyor	2,8	0.0020	0.0010	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.043	0.156	0.020	0.074
11	Tripper Conveyor to Feed Bin	2,8	0.0020	0.0010	430	3,100,000	Fully enclosed transfer point with baghouse dust collector	99	0.009	0.031	0.004	0.015

Emission Source Description		Notes	PM30 Emission Factor (lb/ton)	PM10 Emission Factor (lb/ton)	Maximum Hourly Throughput (ton/hr)	Maximum Annual Throughput (ton/yr)	Control Method	Control Efficiency (%)	Controlled PM30 Maximum Hourly Emission Rate (lb/hr)	ControlledPM 30 Maximum Annual Emission Rate (ton/yr)	Controlled PM10 Maximum Hourly Emission Rate (lb/hr)	Controlled PM10 Maximum Annual Emission Rate (ton/yr)
	Windage from Coal Storage	3,5	--	--	--	--	None	0	--	0.104	--	0.052
	SUBTOTAL								**8.28**	**4.24**	**3.97**	**2.02**
COAL SLURRY FACILITY SOURCES												
12	Feed Bin to Weigh Belt Feeder	2,8	0.0020	0.0010	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.043	0.156	0.020	0.074
13	Weigh Belt Feeder to Rod Mill Feed Chute	2,8	0.0020	0.0010	430	3,100,000	Fully enclosed transfer point with dust suppression sprays	95	0.043	0.156	0.020	0.074
	SUBTOTAL								**0.09**	**0.31**	**0.04**	**0.15**
SLAG TRANSPORT AND STORAGE												
	Slag Disposal Truck Traffic	4	8.5	2.26	0.40	3,500	Apply dust suppressant	80	0.680	2.975	0.181	0.791
	Slag Storage Load-in		Nil	Nil			Wet slag	100	0.000	0.000	0.000	0.000
	Windage from Slag Storage	3,6	--	--	--	--	None	0	--	0.027	--	0.013
	Slag Storage Load-out	7	0.0053	0.0025	39	281,780	None	0	0.207	0.748	0.098	0.354
	SUBTOTAL								**0.89**	**3.75**	**0.28**	**1.16**
	TOTAL								**9.25**	**8.30**	**4.28**	**3.33**

4.1.6 Cooling Towers

Table 4.1-11 shows the expected maximum particulate matter emissions from the cooling towers resulting from drift. Alternate feedstock cases have shown slightly different conditions for the two cooling towers, which would affect emissions rates. The emission estimates below are based on 100% PRB coal feed to the plant, the Siemens-Westinghouse turbine power block (606 MW net nominal plant output), and eight cycles of concentration, and are indicative of the maximum combined particulate matter release. The drift rate is based on 0.001% of the tower recirculation rate as provided by equipment suppliers and reflects the use of high efficiency drift eliminators. The total dissolved solids (TDS) content of the drift is the maximum value estimated from water quality measurement data for the makeup water (the water quality data from which such maxima were derived are provided in Appendix A, Exhibit A-6). Table 4.1-11 shows emissions for the combined Phase I and II cooling towers.

Table 4.1-11
Particulate (PM_{10}) Emissions from Cooling Tower Drift (Per Phase)

	Power Block Cooling Tower	Gasification/ASU Cooling Tower
Duty (MMBtu/hr)	1,743	690
Recirculation Rate (10^6 lb/hr)	116	46
Drift (lb/hr)	1160	460
TDS (ppmw)	2700	2700
PM_{10} Emission (lb/hr/tower)	3.1	1.2
Total PM_{10} **(Phase 1 and II, TPY)**	38.4	

The Power Block cooling tower is configured with 12 cells, and the smaller Gasification/ASU cooling tower with 5 cells. The characteristics of each cell are shown in Table 4.1-12.

Table 4.1-12
Cooling Tower Characteristics (Per Cell)

Characteristic	Value
Exhaust Flow, 10^6 acfm (wet)	1.37
Exhaust Temperature, ^oF	104
Outlet Elevation (above grade), ft	48
Outlet Diameter, ft	33

4.1.7 Auxiliary Boilers

The auxiliary boilers will normally operate only when steam is not available from the gasifiers or HRSGs. The annual capacity factor for these boilers is estimated at 25% or less. The auxiliary boilers will be equipped with low NOx burners for emission control. Emission rates based on supplier guarantees for similar equipment are shown in Table 4.1-13.

Table 4.1-13
Maximum Auxiliary Boiler Short-Term and Annual Emission Rates
(Phase I and II)

	lb/hr	ton/year*	Basis
NOx	9.4	10	Low NOx burner, 30 ppmvd (@ 3% O2)
SO2	0.74	0.82	1 grain/100 scf in pipeline gas
CO	19	21	100 ppmvd (@ 3% O2)
PM_{10}	1.3	1.4	0.005 lb/million Btu, HHV
VOC	1.0	1.1	10 ppmvd (@ 3% O2)

Annual emission based on 25% maximum annual capacity factor.

4.1.8 Emergency Diesel Engines.

Other than the emergency uses for which they are intended, the diesel engines driving the emergency generators and fire protection pumps will each be operated no more than 100 hours per year. Emissions for each engine are estimated using accepted agency-published factors (AP-42) and low sulfur diesel fuel. Table 4.1-14 shows the maximum short-term and annual non-emergency emissions for each engine.

Table 4.1-14
Emergency Diesel Engines Emissions (Phase I and II)

Diesel Engine	Approx Capacity, ea	Total No. of Engines - Phases I plus II	Short-term emission (lb/hr)					Annual emission (ton/yr)				
			NOx	SO2	CO	PM_{10}	VOC	NOx	SO2	CO	PM_{10}	VOC
Emergency generators – gasification area	2 MW	2	129	2	30	4	4	6.4	0.1	1.5	0.2	0.2
Emergency generators – power block	350 kW	2	29	2	6	2	2	1.5	0.1	0.3	0.1	0.1
Fire pumps	300 hp	4	37	2.5	8.0	2.6	3.0	1.9	0.1	0.4	0.1	0.1

4.2 Lead and Non-Criteria Pollutants

4.2.1 Lead Emissions

Plant emission rates of trace amounts of lead were estimated from published information for a similar IGCC facility (NETL - National Energy Technology Laboratory, U.S. Dept of Energy, *Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report*, December 2002). These estimates are shown on Table 4.2-1 in the hazardous air pollutants emission discussion below.

4.2.2 Sulfuric Acid Emissions

Sulfur trioxide (SO_3) emissions, expressed as sulfuric acid (H_2SO_2), for the CTGs and other plant emission sources were estimated based on supplier information and measurements at the Wabash River. These estimates are also shown on Table 4.2-1 in the hazardous air pollutants emission discussion below.

4.2.3 Hazardous Air Pollutant Emissions

Emission rates for HAPs, as identified by the Minnesota Pollution Control Agency, have been estimated for the project using the following sources (listed in order of preference):

- Results of regulatory test programs at Wabash River - adjusted, if appropriate, for the expected worst-case feedstocks slated for use by the Mesaba Energy Project.
- Equipment supplier information.
- Published emission factors and reports applicable to IGCC facilities.
- Engineering calculations and judgment.
- U.S. EPA emission factors (AP-42) for coal combustion.

HAP emissions at the IGCC Power Station will be reduced by the inherently low polluting IGCC technology and many of the same process features that control criteria emissions. A large portion of the heavy metals and other undesirable constituents of the feed will be immobilized in the non-hazardous, vitreous slag by-product and prevented from causing adverse environmental effects. Gaseous and particle-bound HAPs that may be contained in the raw syngas exiting the gasifiers will be totally or partially removed in the syngas particulate matter removal system, water scrubber, and AGR systems described above. In addition, the mercury removal carbon absorption beds will ensure that mercury emissions from the IGCC Power Station will be less than 10 percent of the mercury present in the feedstock as received.

Table 4.2-1 presents a summary of estimated HAPs emissions for the Phase I and II IGCC Power Station. Appendix B presents the methodology used to estimate HAP emissions, shows example calculations, and identifies the sources of HAPs data used.

Table 4.2-1
Annual Hazardous Air Pollutant Emissions (Phase I and II)

CAS # or MPCA #	Compound	Annual Average HAP Emission (ton/yr)				Total Phase I	Phase I and Phase II
		CTGs	TVB	Flare	Fugitive		
75-07-0	Acetaldehyde	0.044	1.6E-04	3.9E-04		0.045	0.089
98-86-2	Acetophenone	0.022	7.9E-05	2.0E-04		0.022	0.045
107-02-8	Acrolein	0.43	1.5E-03	3.8E-03		0.43	0.87
7440-36-0	Antimony	0.027	2.8E-04	7.0E-04		0.028	0.056
7440-38-2	Arsenic	0.059	1.5E-03	3.7E-03		0.064	0.128
71-43-2	Benzene	0.061	0.028	0.071	0.0063	0.167	0.333
100-44-7	Benzyl chloride	1.03	3.7E-03	9.2E-03		1.0	2.1
7440-41-7	Beryllium	0.0064	7.9E-06	2.0E-05		0.0064	0.0128
92-52-4	Biphenyl	0.0025	9.0E-06	2.2E-05		0.0025	0.0051
117-81-7	Bis(2-ethylhexyl)phthalate (DEHP)	0.11	3.9E-04	9.6E-04		0.109	0.218
75-25-2	Bromoform	0.06	2.0E-04	5.0E-04		0.057	0.114
7440-43-9	Cadmium	0.24	5.7E-05	1.4E-04		0.24	0.47
75-15-0	Carbon disulfide	1.13	4.0E-03	1.0E-02	0.034	1.18	2.35
463581	Carbonyl sulfide				0.058	0.058	0.116
532-27-4	Chloroacetophenone, 2-	0.0103	3.7E-05	9.2E-05		0.0104	0.0208
108-90-7	Chlorobenzene	0.032	1.1E-04	2.8E-04		0.032	0.065
67-66-3	Chloroform	0.088	3.2E-04	7.9E-04		0.089	0.179
0-00-5	Chromium, total (1)	0.013	1.1E-03	2.6E-03		0.016	0.033
18540-29-9	Chromium, (hexavalent)	0.0038	3.2E-04	7.9E-04		0.0049	0.0099
7440-48-4	Cobalt (1)	0.0064	1.2E-03	3.0E-03		0.011	0.021
98-82-8	Cumene	0.0078	2.6E-05	6.6E-05		0.0079	0.0159
57-12-5	Cyanide (Cyanide ion, Inorganic cyanides, Isocyanide)	0.140	4.6E-03	1.2E-02	0.0088	0.16	0.33
77-78-1	Dimethyl sulfate	0.071	2.5E-04	6.3E-04		0.072	0.144
121-14-2	Dinitrotoluene, 2,4-	4.2E-04	1.5E-06	3.7E-06		4.2E-04	8.4E-04
100-41-4	Ethyl benzene	0.14	0.032	0.079	5.4E-06	0.25	0.50
75-00-3	Ethyl chloride (Chloroethane)	0.061	2.2E-04	5.5E-04		0.062	0.124
106-93-4	Ethylene dibromide (Dibromoethane)	0.0018	6.3E-06	1.6E-05		0.0018	0.0036
107-06-2	Ethylene dichloride (1,2-Dichloroethane)	0.059	2.1E-04	5.3E-04		0.060	0.119
50-00-0	Formaldehyde	0.42	1.5E-03	3.7E-03	1.1E-06	0.42	0.84
110-54-3	Hexane	0.10	3.5E-04	8.8E-04	1.5E-06	0.10	0.20
7647-01-0	Hydrochloric acid	0.096	3.0E-04	7.4E-04	0.034	0.13	0.26
7664-39-3	Hydrogen fluoride (Hydrofluoric acid)	1.2	5.3E-05	1.3E-04		1.2	2.5

CAS # or MPCA #	Compound	Annual Average HAP Emission (ton/yr)				Total Phase I	Phase I and Phase II
		CTGs	TVB	Flare	Fugitive		
78-59-1	Isophorone	0.86	3.1E-03	7.6E-03		0.87	1.73
7439-92-1	Lead	0.014	6.3E-05	1.6E-04		0.014	0.028
7439-96-5	Manganese	0.025	2.4E-03	5.9E-03		0.034	0.068
7439-97-6	Mercury	0.012	6.6E-04	1.6E-04		0.013	0.026
74-83-9	Methyl bromide (Bromomethane)	1.23	0.011	0.029		1.3	2.5
74-87-3	Methyl chloride (Chloromethane)	0.78	6.0E-03	1.5E-02		0.80	1.61
71-55-6	Methyl chloroform (1,1,1 -Trichloroethane) (4)	0.029	1.1E-04	2.6E-04		0.030	0.060
78-93-3	Methyl ethyl ketone (2-Butanone)	0.58	2.1E-03	5.1E-03		0.58	1.17
60-34-4	Methyl hydrazine	0.25	9.0E-04	2.2E-03		0.25	0.51
80-62-6	Methyl methacrylate	0.029	1.1E-04	2.6E-04		0.030	0.060
1634-04-4	Methyl tert butyl ether	0.051	1.8E-04	4.6E-04		0.052	0.104
75-09-2	Methylene chloride (Dichloromethane)	0.056	5.5E-04	1.4E-03		0.058	0.117
91-20-3	Naphthalene	0.064	8.1E-04	2.0E-03	2.6E-05	0.067	0.133
7440-02-0	Nickel	0.0096	4.2E-03	1.0E-02		0.024	0.048
108-95-2	Phenol	0.95	1.2E-02	3.0E-02	7.8E-08	0.99	1.98
123-38-6	Proprionaldehyde	0.561	2.0E-03	5.0E-03		0.568	1.136
7784-49-2	Selenium	0.014	2.4E-04	5.9E-04		0.015	0.029
100-42-5	Styrene	0.037	1.3E-04	3.3E-04		0.037	0.075
127-18-4	Tetrachloroethylene (Perchloroethylene)	0.063	2.3E-04	5.7E-04		0.064	0.129
108-88-3	Toluene	0.00081	0.0112	0.0280	6.6E-04	0.041	0.081
108-05-4	Vinyl acetate	0.011	4.0E-05	1.0E-04		0.011	0.023
1330-20-7	Xylenes	0.055	0.013	0.032	1.0E-05	0.10	0.20
	Total federal HAPs	***11.4***	***0.2***	***0.4***	***0.1***	***12.0***	***24.1***
	Other Emissions						
56-55-3	Benz[a]anthracene	5.6E-05	2.0E-07	5.0E-07		5.7E-05	1.1E-04
207-08-9	Benzo(k)fluoranthene	1.6E-04	5.8E-07	1.4E-06		1.6E-04	3.3E-04
50-32-8	Benzo[a]pyrene	5.6E-05	2.0E-07	5.0E-07		5.7E-05	1.1E-04
218-01-9	Chrysene (Benzo(a)phenanthrene)	1.5E-04	5.3E-07	1.3E-06		1.5E-04	3.0E-04
193-39-5	Indeno(1,2,3-cd)pyrene	9.1E-05	3.2E-07	8.1E-07		9.2E-05	1.8E-04
3697-24-3	Methylchrysene, 5-	3.2E-05	1.1E-07	2.8E-07		3.2E-05	6.5E-05
7664-93-9 14808-79-8	Sulfuric acid and sulfates	62.0	0.2	0.6		62.8	125.6
	Other VOC				8.3	8.3	16.6
	Hydrogen sulfide				8.6	8.6	17.2

CAS # or MPCA #	Compound	Annual Average HAP Emission (ton/yr)				Total Phase I	Phase I and Phase II
		CTGs	TVB	Flare	Fugitive		
	Total Volatile Organic Compounds (VOC)	9.6	0.1	0.4	8.4	18.6	37.1
	Total Reduced Sulfur (TRS) Compounds	1.1	0.004	0.010	8.7	9.8	19.7

4.2.3.1 Mercury

The volume of pre-combustion syngas present at the time of its clean-up in the E-Gas™ process is about one hundred times less than the volume of the post-combustion gas handled in a typical conventional pulverized coal-fired boiler. An inherent advantage that IGCC technology has over such conventional systems is that gas clean up equipment can be much smaller in size and the residence time for allowing contact between a chemical (like mercury) and an absorbent (like activated carbon) can be increased, thereby providing for greater pollutant removal efficiency. This pre-combustion gas clean-up process allows for highly effective mercury removal rates, which in the case of Mesaba One and Mesaba Two will be at least 90 percent of the as-received combustion concentration present in its incoming fuel. For Mesaba One and Mesaba Two, this translates to maximum annual mercury emissions of only 54 pounds on a twelve month rolling average. Figure 4.2-1 shows how mercury is expected to partition throughout the IGCC Power Station.

4.3 Carbon Dioxide

Carbon dioxide emissions from the IGCC Power Station are a function of the feedstock consumed and the Station's net heat rate (a measure of the overall efficiency under which the energy in the feedstock is converted to electricity). The characteristics of the feedstock that dictate the rate at which CO_2 is emitted are its carbon content and higher heating value. Figure 4.3-1 illustrates the rates at which CO_2 will be produced by Mesaba One and Mesaba Two when using 100% bituminous coal and 100% subbituminous coal as a feedstock. The CO_2 emission rates shown in Figure 4.3-1 do not account for any CO_2 removal that would occur as a result of the equipment additions described in Section 2.4.3.4. For purposes of comparison, the CO_2 generation rate of Sherco 3 (a pulverized coal-fired electric generating unit using western subbituminous coal) is also shown in Figure 1.8-3.

Emissions of CO_2 from other large coal-fired electric generating units in Minnesota are shown in comparison with Mesaba One and Mesaba Two in Figure 1.8-4. For those units shown in Figure 1.8-4 that use wet limestone scrubbers (for example Boswell Energy Center and Sherburne County Unites 1 and 2) CO_2 emissions will be underestimated as CO_2 is produced as a consequence of removing SO_2 from the combustion gases. For those units that use lime spray dryers to remove SO_2 from their combustion gases (for example, Sherburne County Unit 3), CO_2 is produced as a consequence of producing lime (CaO) from limestone ($CaCO_3$). Some SO_2 will be removed by soluble oxides present in coal ash, thereby lowering the quantity of CO_2 produced as a result of reacting SO_2 and limestone slurry added for such reason.

Figure 4.2-1 Expected Mercury Partitioning in the IGCC Power Station (Mesaba One and Mesaba Two)

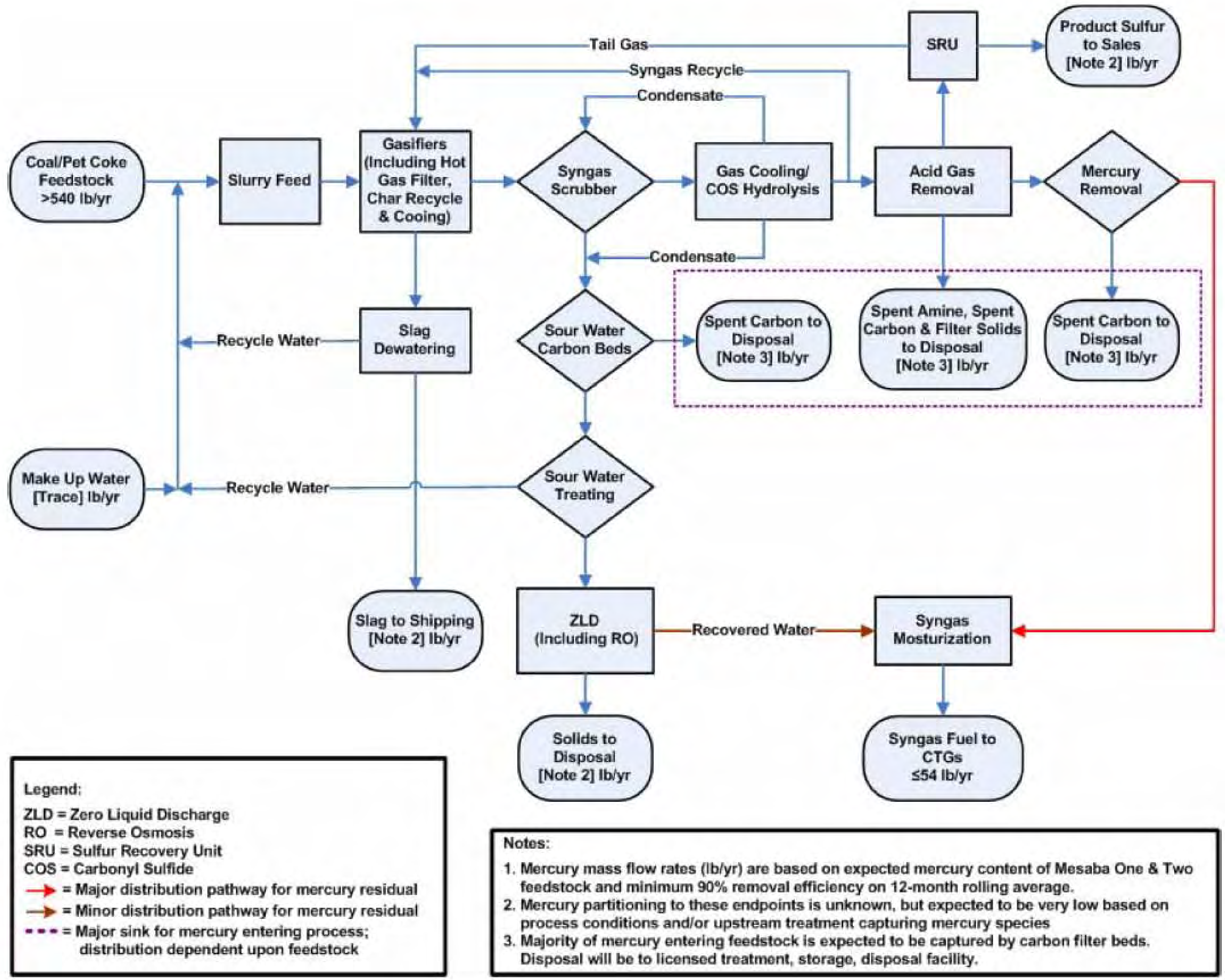


Figure 4.2-2 Carbon Dioxide Emissions From Mesaba Energy Project vs. Sherco Unit 3

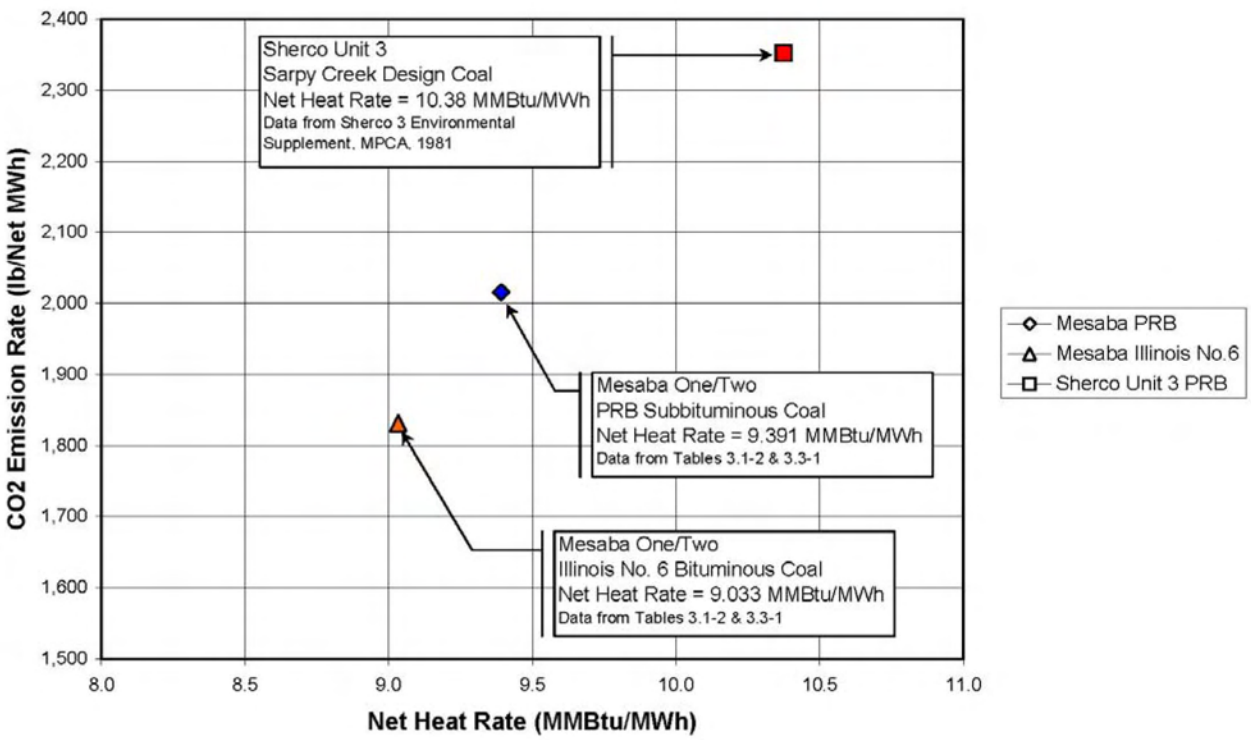
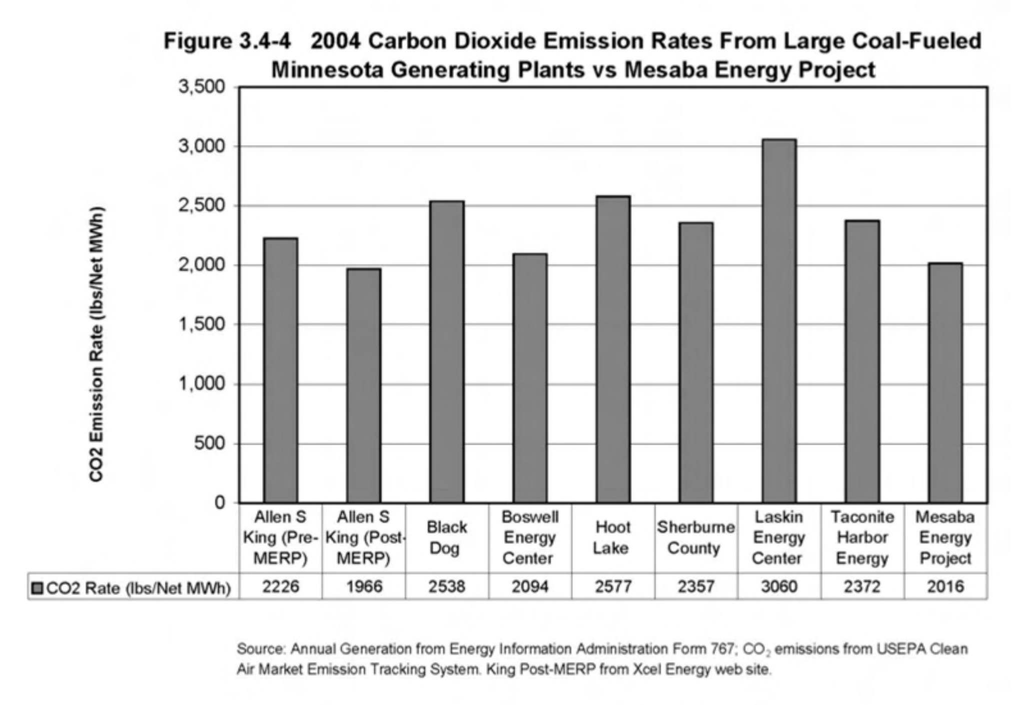


Figure 4.2-3 2004 Carbon Dioxide Emission Rates From Large Coal-Fueled Minnesota Generating Plants vs. Mesaba Energy Project



5. BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

This section presents a BACT analysis for the IGCC Power Station. As discussed above, the IGCC Power Station will be a new major source of regulated pollutant emissions under the PSD regulations, which require a BACT analysis for each pollutant that is emitted in excess of the regulatory thresholds. Table 5.0-1 presents the IGCC Power Station emissions compared to the PSD significance thresholds and the applicability of PSD review.

Table 5.0-1
Potential IGCC Power Station Emissions and PSD Thresholds

Pollutant	PSD Significance Threshold (TPY)	Plantwide Potential to Emit (TPY)	PSD Review Required?
Carbon Monoxide	100	2539	Yes
Nitrogen Oxides	40	2872	Yes
Sulfur Dioxide	40	1390	Yes
Particulate Matter (PM)	25	15	Yes
Particulate Matter < 10 microns (PM_{10})	15	491	Yes
Ozone (VOC)	40	197	Yes
Lead	0.6	0.03	No
Sulfuric Acid Mist	7	131	Yes
Hydrogen Sulfide	10	17	Yes

5.1 BACT Results Summary

A summary of the proposed BACT controls and associated emission rates for each emission unit is shown in Table 5.1-1. This analysis includes the syngas-fired CTGs, tank vent boilers, cooling towers, flare, emergency diesel generators, and fire water pumps.

Table 5.1-1
Proposed BACT for the IGCC Power Station

Pollutant	Control	Emissions Limits
Syngas-Fired Combustion Turbines (emissions shown per CTG)		
NO_x	Diluent Injection	15 ppm NOx @ 15%O_2; 156 lb/hr per CTG on syngas fuel
		25 ppm NOx @ 15%O_2; 198 lb/hr per CTG on natural gas fuel
CO	Good Combustion Practice ("GCP")	15 ppm @ actual O_2 (above 50% load) 95 lb/hr per CTG
PM/PM_{10}	GCP, gas cleanup, Gaseous Fuels only	25 lb/hr
SO_2	Gas cleanup/Use of Clean Syngas	76 lb/hr SO_2 per CTG, 30-day rolling average; (approx. 50 ppmvd sulfur, as H_2S, in undiluted syngas)
VOC	GCP	9 lb/hr per CTG
Lead	Gas cleanup/Use of Clean Syngas	0.007 tons/yr per CTG
H_2SO_4	Gas cleanup/Use of Clean Syngas	5.3 lb/hr, 30-day rolling average
Cooling Towers		
PM_{10}	High Efficiency Drift Eliminators	0.001% drift
Tank Vent Boiler		
NO_x, SO_2, CO, VOC, PM_{10}	GCP, Gas cleanup/Use of Clean Syngas or Natural Gas	0.3 lbsNOX/MMBtu; 30-day rolling average 0.035 lbs SO2/MMBtu; 30-day rolling avg. 0.004 lbs VOC/MMBtu; 3-hr avg. 0.09 lbs CO/MMBtu; 3-hr avg. 0.01 lbs PM10/MMBtu; 3-hr avg.
Flare		
NO_x, SO_2, CO, VOC, PM_{10}	Good Flare Design, Flaring only treated Syngas	0.064 lbsNOX/MMBtu; 24-hr avg. 0.105 lbs SO2/MMBtu; 24-hr avg. 0.006 lbs VOC/MMBtu; 3-hr avg. 1.5 lbs CO/MMBtu; 3-hr avg. 0.01 lbs PM10/MMBtu; 3-hr avg.
Auxiliary Boiler		
NO_x, SO_2, CO, VOC, PM_{10}	Low NOX burners, good combustion practice, pipeline natural gas only	0.036 lbsNOX/MMBtu; 24-hr avg. 0.003 lbs SO2/MMBtu; 24-hr avg. 0.004 lbs VOC/MMBtu; 3-hr avg. 0.074 lbs CO/MMBtu; 3-hr avg. 0.01 lbs PM10/MMBtu; 3-hr avg.
Fire Pumps		
NO_x, SO_2, CO, VOC, PM_{10}	GCP, limited hours of operation, and use of very low-sulfur fuel oil	Less than 100 hrs/yr operation; Very low sulfur fuel oil
Emergency Diesel Generators		
NO_x, SO_2, CO, VOC, PM_{10}	GCP, limited hours of operation, and use of very low-sulfur fuel oil	Less than 100 hrs/yr operation; Very low sulfur fuel oil

The following sections describe the BACT review process in general, the unique characteristics of IGCC, and the individual control technology evaluations for each emission unit and pollutant that support the summary in Table 5.1-1.

To properly evaluate BACT for the emission units at an IGCC plant, an understanding of the IGCC process is important. Detailed process descriptions for the proposed facilities are given in Section 2.3 and 2.4 of this application. Section 5.3 provides a general overview of IGCC and its unique characteristics for BACT evaluation. Section 5.4 describes existing or proposed IGCC facilities in the United States, their permitted emission levels, and compares such levels to those proposed for Mesaba One and Mesaba Two.

5.2 BACT Review Process

BACT is defined in the PSD regulations as:

> *"... an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source ... which [is determined to be achievable], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs." [40 C.F.R. 52.21(b)(12)]*

In a December 1, 1987 memorandum from the EPA Assistant Administrator for Air and Radiation, the EPA provided guidance on the "top-down" methodology for determining BACT (EPA, 1987). The "top-down" process involves the identification of all applicable control technologies according to control effectiveness. The owner or operator then evaluates the "top," or most stringent, control alternative. If the most stringent is shown to be technically or economically infeasible, or if secondary environmental impacts are severe enough to preclude its use, then the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts.

The five basic steps of a top-down BACT analysis are shown in Table 5.2-1 below (from the EPA's Draft New Source Review Workshop Manual, October 1990, EPA Office of Air Quality Planning and Standards).

Table 5.2-1
Steps Involved in Top-Down BACT Analysis

Step 1.	Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation.
Step 2.	Eliminate all technically infeasible control technologies.
Step 3.	Rank remaining control technologies by control effectiveness and tabulate a control hierarchy.
Step 4.	Evaluate most effective controls and document results.
Step 5.	Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

The BACT assessment described herein is in compliance with the EPA guidelines set forth above.

The EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements that must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner or otherwise. First, the BACT analysis must include consideration of the most stringent available technologies; that is, those technologies that provide the "maximum degree of emissions reduction." Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts" contained in the record of the permit decisions.

The minimum control efficiency to be considered in a BACT analysis must result in an emission rate less than or equal to any New Source Performance Standard (NSPS) emission rate applicable to the source. The applicable NSPS represents the maximum allowable emission limit from the source.

As part of the IGCC Power Station BACT analysis, control options for potential reductions in criteria pollutants were identified. Potential control options were identified by researching the EPA database known as the RACT/BACT/LAER Clearinghouse (RBLC), drawing upon previous environmental permitting for similar units, engineering experience, and researching available literature. Available controls are further evaluated based on an analysis of economic, environmental, and energy impacts.

Assessing the technical feasibility of emission control alternatives is discussed in EPA's draft "New Source Review Workshop Manual." Using terminology from this manual, if a control technology has been "demonstrated" successfully for the type of emission unit under review, it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. An available technology is one that is commercially available, meaning that it has advanced through the following steps:

- Concept stage.
- Research and patenting.
- Bench scale or laboratory testing.
- Pilot scale testing.
- Licensing and commercial demonstration.
- Commercial sales.

Applicability involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission unit), but also involves consideration of the physical and chemical characteristics of the exhaust gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit depending on differences in the exhaust gas streams' physical and chemical characteristics.

For the IGCC Power Station's BACT analysis, the available control options were identified by reviewing the EPA's RBLC and by consulting available literature and vendors on control options for IGCC. Applications and/or permits from existing IGCC facilities were also reviewed and studied. Together, such information was used in determining BACT for the IGCC Power Station. A brief summary of the IGCC process is provided in Section 5.3, and a description of other IGCC facilities (operating. or permitted, but not yet constructed) in the United States and their emissions limits is provided in Section 5.4.

5.3 IGCC Process Description

To evaluate possible emission control technologies, it is first important to describe and understand the unique IGCC process. This section presents a summary of the various sub processes that make up the IGCC process (more detailed process descriptions are included in Sections 2.3 and 2.4).

The primary function of the gasification portion of the IGCC process is the conversion of coal, petroleum coke, or a combination of those feedstocks into a synthesis gas (syngas), which can then be used to fuel CTGs in lieu of using natural gas or liquid fuels as a primary fuel. Gasification technologies have been developed by several companies and can be used to create syngas for many uses, including chemical plant feedstocks, pipeline quality natural gas, clean liquid fuels, and hydrogen to power fuel cells and ultimately electric generation, pursuant to U.S. Department of Energy's FutureGen Program.

The proposed gasification process is designed to convert the carbon-based slurried feedstock into a syngas product (essentially a mixture of H_2 and CO, with significantly smaller amounts of other constituents), enabling the separation of many contaminants from the product syngas. One of the primary raw syngas clean-up steps involves the removal of sulfur species and the production of either elemental sulfur or sulfuric acid. Removal of over 99 percent of the sulfur (present primarily as H_2S) can be achieved using commercial amine-based acid gas scrubbing technology on higher sulfur feedstocks (>97 percent removal is expected on low sulfur PRB coals). For processes that incorporate sulfur recovery, molten elemental sulfur will be generated from the sulfur recovery equipment. Sulfur removal in the AGR system and SRU minimize SO_2 emissions from the syngas combustion in the CTGs.

The IGCC Power Station will utilize the ConocoPhillips' E-Gas™ gasification technology, which is an oxygen-blown, entrained flow process based on a coal or coal/petroleum coke slurry feed to a two-stage gasifier, coupled to a unique high-temperature heat recovery unit (syngas cooler). A two-train gasifier system is being proposed for each of the IGCC Power Station's two phases, with an additional gasifier train for each phase to be used as a spare.

In addition to the gasifier, the IGCC process also includes a number of gas clean-up steps. After exiting the gasifier, the raw hot syngas is cooled prior to filtration of the particulate matter. The particulate matter removal system consists of a hybrid hot gas cyclone and a filter vessel with numerous porous filter elements to remove particles, including unreacted char. Removal efficiency is expected to be better than 99.9%. Removed PM is recycled to the first stage of the gasifier. After particulate matter removal, the syngas proceeds to additional syngas cleanup and cooling steps. In the first of these steps, the syngas is scrubbed with recycled sour water (water with dissolved sulfur compounds condensed from the syngas) to remove chlorides and trace metals.

In the next step, a carbonyl sulfide (COS) hydrolysis unit is provided to convert the small amount of COS in the syngas to H_2S, which is more efficiently removed in the AGR system. This configuration permits a higher level of sulfur removal. After hydrolysis, the syngas is cooled in process heat exchangers to utilize the available low-temperature heat. The cooled sour syngas is fed to the AGR system where it is contacted with an amine absorbent to remove the H_2S and produce a clean product syngas. The solvent is regenerated and recycled for reuse, and the off-gas containing the recovered H_2S is fed to the SRU, which uses the industry-standard Claus process to convert the H_2S to gaseous elemental sulfur. The sulfur is recovered and stored in molten form and potentially sold as a commercial by-product. After the sulfur is removed, the syngas passes through a fixed bed of activated carbon that is specially impregnated with additives to remove mercury from the syngas stream. The mercury removal system will be designed to remove enough mercury so that the mercury content of the HRSG stack gas is no more than 10% of the mercury content originally in the solid feedstock. After mercury removal, the product syngas is moisturized, heated, and diluted with nitrogen before being used as fuel for power generation in the combined cycle CTGs.

Additional facilities to support the gasification and power generation systems include a tank vent collection and boiler system, a flare for use during startups, shutdowns and for combusting excess syngas during short-term CTG outages or other plant upsets (treated product syngas would be combusted in short-term CTG outages), cooling towers, and emergency diesel generators and fire water pumps.

5.4 Inherently Lower Polluting Technology

As introduced in Section 5.2, the first step in a BACT determination process is to identify all available control technologies that could potentially be used to minimize the emissions of the source and pollutant under evaluation. The most common control technologies considered in a BACT analysis are add-on control measures. However, it is sometimes possible to modify the production process or work practices to improve the emissions performance of a proposed project. These types of process modifications/measures, when applicable, should also be considered in a BACT analysis. However, EPA has not historically required a BACT analysis to consider completely “redefining the design” of the proposed process (1990 Draft New Source Review Workshop Manual, Section IV.A.3). Nevertheless, IGCC technology is indeed the lowest emitting coal-based electricity generating technology available. This section of the BACT analysis compares Mesaba One and Mesaba Two to other potential coal-based electrical generating technologies. The other portions of this BACT analysis address the potential controls specific to minimizing the emissions from the IGCC process.

5.4.1 Generalized Comparison with Conventional Coal-Fired Power Plants

Table 5.4-1 illustrates the proposed emissions performance from Mesaba One and Mesaba Two compared to two other available coal-based power generation technologies: Pulverized Coal (“PC”)-fired Boiler and Circulating Fluidized Bed (“CFB”) Boiler. IGCC emissions for all criteria pollutants, except VOC, are well below the emissions from a well-controlled PC or CFB power plant. VOC emissions are comparable.

Table 5.4-1
Comparison of Emissions from Coal Based Electrical Generating Technologies

Pollutant	Mesaba One and Mesaba Two* lbs/MMBtu coal	Pulverized Coal [1] lb/MMBtu coal	Circ. Fluidized Bed lb/MMBtu coal
NO_x	0.057	0.076	0.09
SO_2	0.025	0.104	0.15
PM	0.009	0.016	0.015
VOC	0.0032	0.0034	0.004
CO	0.0345	0.144	0.15

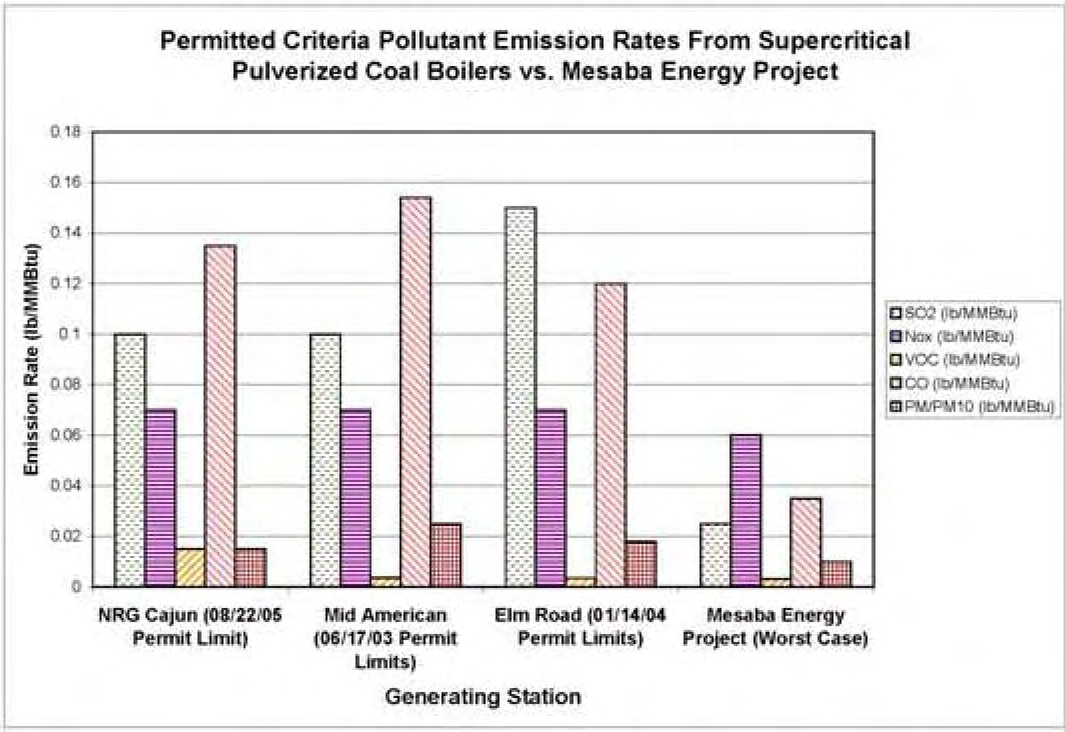
*The emission rates in lbs/MMBtu are based on the heat input to the gasifier, not the CTG.
[1]U.S. EPA Presentation at Pittsburgh Coal Conference Sept. 2005, "Environmental Impact Comparisons IGCC vs. PC Plants."

This comparison illustrates that Mesaba One and Mesaba Two would utilize the lowest polluting commercially available process for generating electricity from coal and/or petroleum coke. The proposed use of an inherently lower polluting, innovative technology does not necessarily excuse an applicant from also considering the use of additional add-on controls to further lower the emissions of the plant. However, the fact that emissions from Mesaba One and Mesaba Two are significantly below competing technologies decreases the need for, and relative value of, further controls.

5.4.2 Mesaba vs. Recently Permitted Supercritical Pulverized Coal Plants

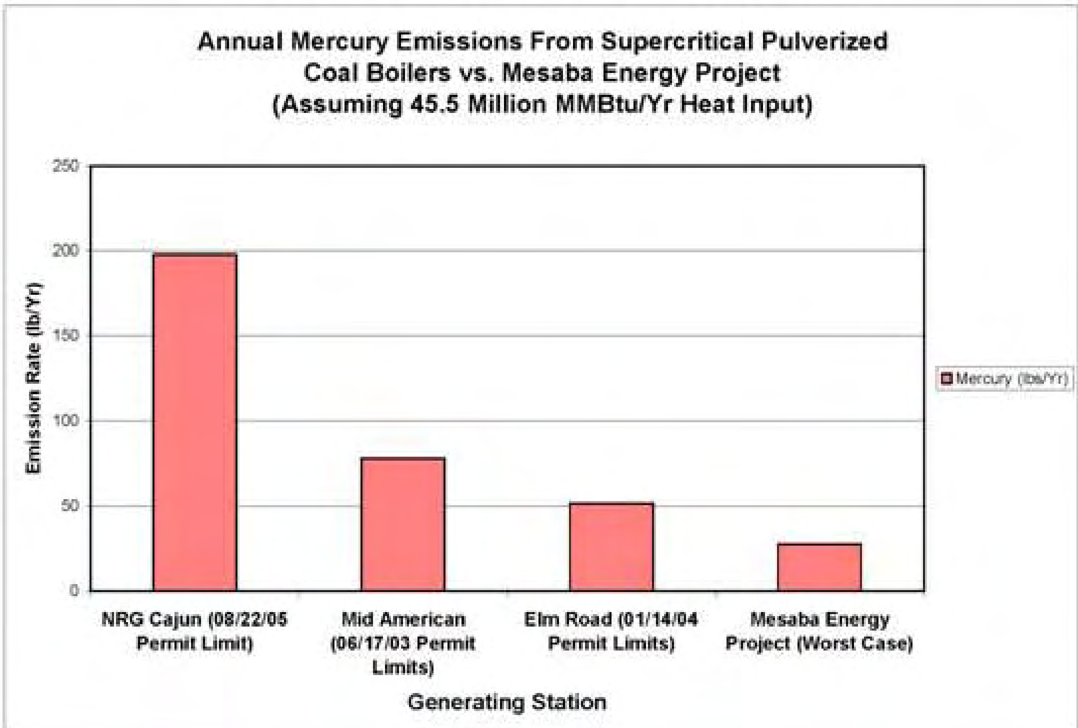
The analysis below compares Mesaba to the following three recently permitted, utility-scale, supercritical pulverized coal ("SCPC") plants: i) NRG Cajun in Louisiana, permitted August 22, 2005; ii) Mid American Council Bluffs Energy Center Unit 4 in Iowa, permitted June 17, 2003; and iii) Elm Road in Wisconsin, permitted January 14, 2004. This group of plants typifies the emissions profile of an SCPC plant with a full suite of pollution control technology. Figure 5.4-1 below compares the permitted criteria pollutant levels for each of these facilities with the maximum expected emission levels from Mesaba One and Mesaba Two. The first column for each plant represents sulfur dioxide emissions. Mesaba One and Mesaba Two's sulfur emissions are 75-85% less than those of the best comparison SCPC facility. The second column for each plant represents emissions of NO_X. NO_X emissions from Mesaba One and Mesaba Two are lower than the emissions rates of these newest coal plants by about 15%. The third column for each plant represents volatile organic compounds (VOCs) emission rates. Mesaba One and Mesaba Two's VOC emission rate is comparable to two of the comparison units, but about 80 percent less than one of the comparison units. Column four for each plant represents carbon monoxide (CO) emission rates. Compared to the most recently permitted SCPC facilities, carbon monoxide (CO) emission rates for Mesaba One and Mesaba Two are 70-80% lower. Finally, column five for each plant represents particulate matter emissions. Particulate matter emissions from Mesaba One and Mesaba Two are 30-60% less than those from the SCPC comparison plants.

Figure 5.4-1. All Criteria Pollutants: Mesaba vs. Newest SCPC Plants



With respect to mercury as shown in Figure 5.4-2, mercury emissions from Mesaba One and Mesaba Two will be half of the mercury emissions from the Elm Road SCPC plant in Wisconsin, and will represent a two-thirds to seven-eighths reduction in the mercury emissions from the other recently permitted SCPC plants in Iowa and Louisiana.

Figure 5.4-2. Mercury: Mesaba vs. Recently Permitted Coal Plants



5.4.3 Mesaba vs. Nation's Cleanest Coal Plants: Criteria Pollutants

Mesaba One and Mesaba Two will achieve substantially better across-the-board criteria pollutant emission results than the nation's cleanest coal-fueled power plants permitted over the past 10 years. In order to establish the comparison group of power plants to demonstrate this, regulatory decision-making was reviewed to find the coal-fueled power plants that emit the least of each criteria pollutant to compare to the emissions from Mesaba One and Mesaba Two. The comparison plants were selected as "best in class" by conducting a review of U.S. EPA's RACT/BACT/LAER clearinghouse ("RBLC") and other governmental agency databases. All recently permitted, utility scale, coal-fueled electric generating units of any type that have triggered review under the Prevention of Significant Deterioration (PSD) regulations and were subject to top-down BACT review were reviewed. The emissions of the coal facilities that have met the most stringent BACT determinations for any coal-fueled, utility scale source were selected to compare emission rates for the criteria pollutants sulfur dioxide, nitrogen oxides, particulate matter, volatile organic compounds, and carbon monoxide.

The comparisons illustrate that whenever a combustion facility achieves emission parity with Mesaba One and Mesaba Two for one pollutant, that same facility has significantly, and often times dramatically, higher emissions of other pollutants than do Mesaba One and Mesaba Two. The fact that the emission rate of each criteria pollutant from Mesaba One and Mesaba Two is essentially equal to or lower than the corresponding emission rate from the best controlled coal-fueled plants in the nation – regardless of the technology utilized by such plants, underscores the superior environmental profile of Mesaba One and Mesaba Two. Figures 5.4-3 though 5.4-7 illustrate the results of comparing emission rates from Mesaba One and Mesaba Two to these "best in class" existing coal-fueled plants.

Figure 5.4-3. Sulfur Dioxide: Mesaba One and Mesaba Two Emission Rates vs. Cleanest Coal Plants

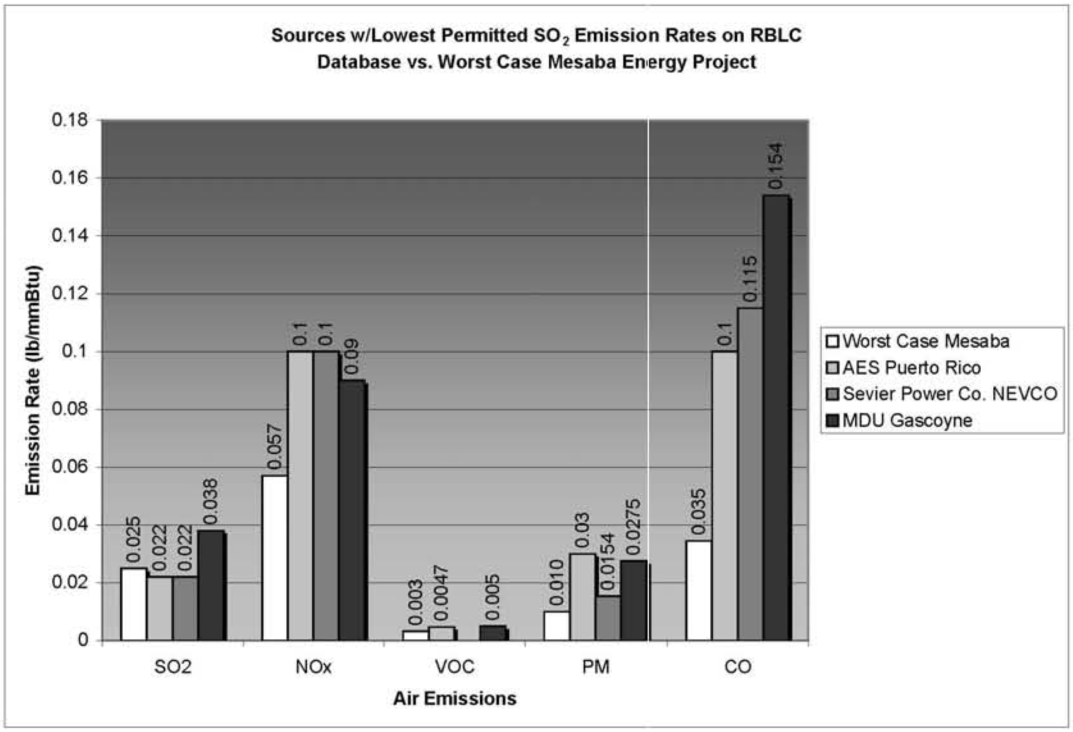


Figure 5.4-4. Nitrogen Oxides: Mesaba One and Mesaba Two Emission Rates vs. Cleanest Coal Plants

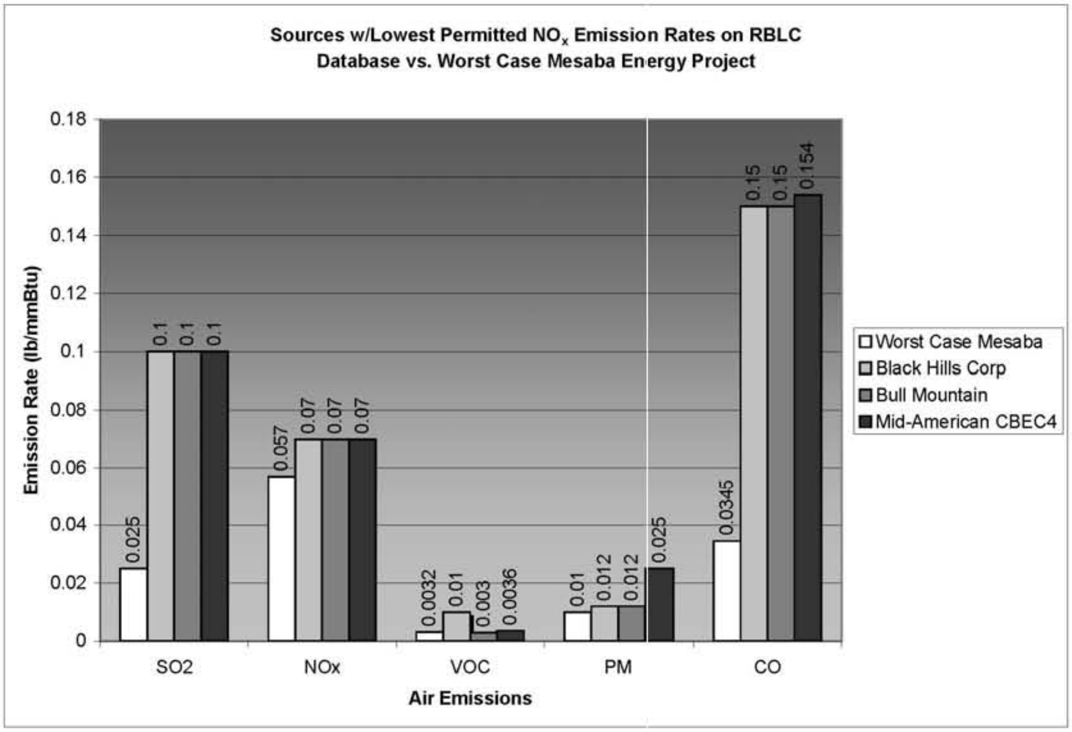


Figure 5.4-5. Particulate Matter: Mesaba One and Mesaba Two Emission Rates vs. Cleanest Coal Plants

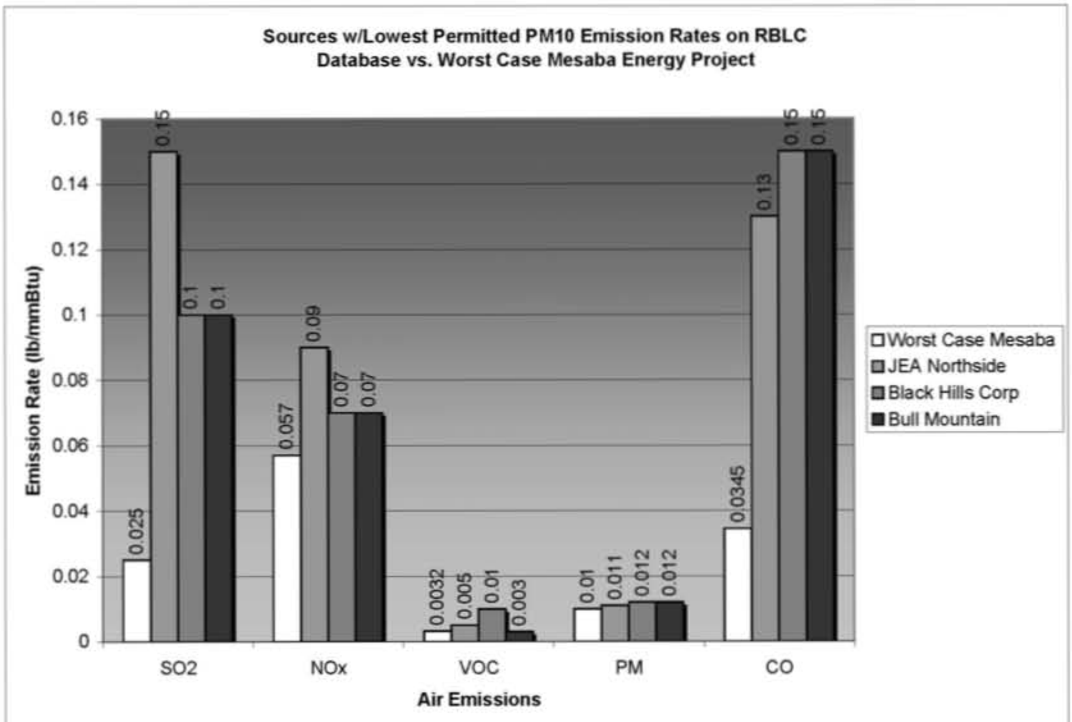


Figure 5.4-6. VOC: Mesaba One and Mesaba Two Emission Rates vs. Cleanest Coal Plants

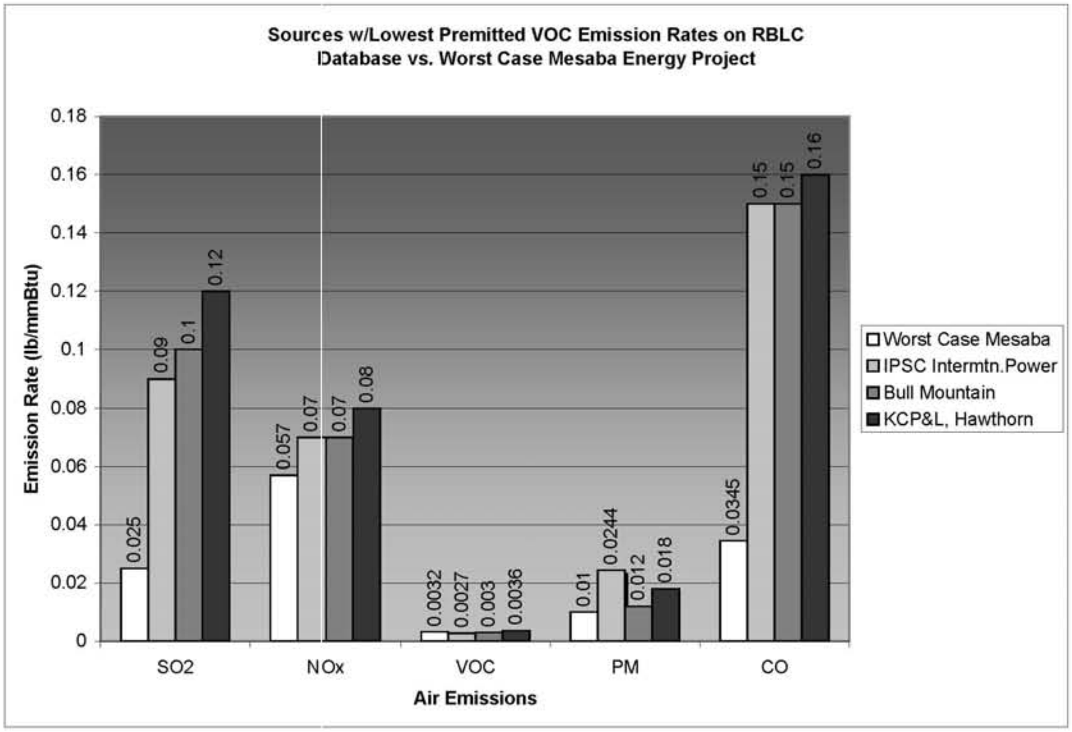
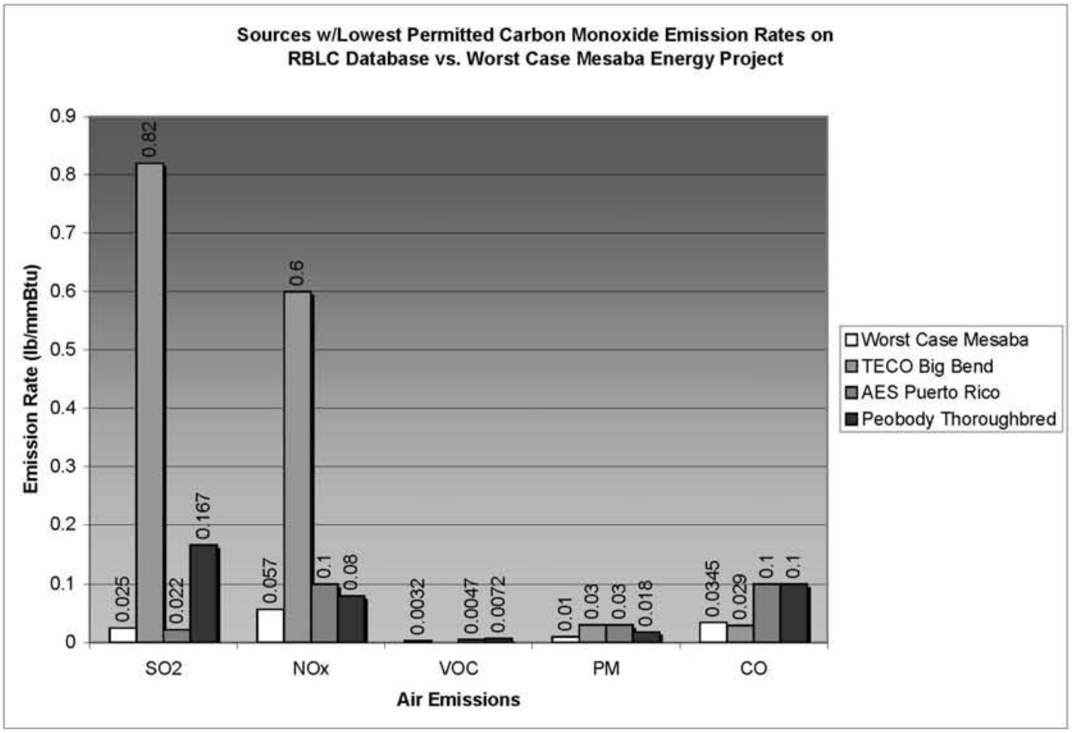


Figure 5.4-7. Carbon Monoxide: Mesaba One and Mesaba Two Emission Rates vs. Cleanest Coal Plants



In sum, the superior across-the-board emission rates achieved by Mesaba One and Mesaba Two in comparison to those of traditional technologies are dramatic.

The remainder of this BACT analysis discusses the various control options specific to IGCC processes and demonstrates that the proposed IGCC Power Station would achieve the lowest emissions rate technically and economical feasible for a such processes.

5.5 Existing and Permitted IGCC Facilities

During the review of available control technologies, existing BACT determinations from conventional pulverized coal (PC) boilers and gas-fired CTGs were examined. Emphasis was given to BACT determinations from existing and permitted IGCC plants, since the power generation and emission control technologies used in a PC plant are significantly different from the IGCC process.

For this BACT analysis, the available control options were identified by querying the RBLC and by consulting available literature and vendors on control options for IGCC. In addition, applications and/or permit information from the facilities listed below were reviewed, studied, and considered. Such information is what was used in this analysis of the IGCC BACT. A summary of the other permitted IGCC plants in the United States and their emissions limits is presented in this section, and include the following:

- SG Solutions, Wabash River Generating Station, West Terre Haute, IN (operating).
- Tampa Electric Company, Polk Power Station, Mulberry, Florida (operating).
- We Energies, Elm Road Generating Station, Wisconsin (permitted).
- Global Energy, Inc.'s Kentucky Pioneer Energy LLC, Trapp, Kentucky (permitted).
- Global Energy, Inc.'s Lima Energy Company, Lima, Ohio (permitted).

The air permits, BACT analyses and additional literature for each of these existing or proposed facilities was reviewed. Each facility is discussed briefly below and Table 5.5-1 presents the criteria pollutant emission levels permitted for each facility. The facilities that were subject to BACT determinations are listed as such.

Wabash River Generating Station and PSI Combined Cycle Power Station: The DOE and a Joint Venture formed in 1990 between Destec Energy Inc. and Public Service of Indiana (PSI) initiated the Wabash River Coal Gasification Repowering Project. The gasification island includes an E-Gas (originally developed by Dow Chemical and known earlier as Destec Technology, and now operated by SG Solutions) two-stage, oxygen blown gasifier with full heat recovery that is integrated with the power block. This facility has been operating since 1995.

Tampa Electric Company Polk Power Station: The DOE partly funded the Polk Power Station IGCC project. The facility includes a Texaco (now GE Energy) oxygen blown gasifier with full heat recovery using both radiant and convective syngas coolers. The GE STAG-107FA power block integrates process syngas, steam, and nitrogen. This IGCC facility has been operating since 1996.

Global Energy Kentucky Pioneer Power Station: Global Energy USA (Global), owner of Kentucky Pioneer Energy, LLC, negotiated with the DOE and Clean Energy Partners, LP to acquire a conditionally approved IGCC Demonstration Project. The British Gas/Lurgi (BG/L) slagging fixed-bed gasification technology has been proposed in a new 540 MW (net) IGCC facility using both coal and refuse derived fuel as a feedstock. The gasification system would be coupled with Fuel Cell Energy, Inc.'s molten carbonate fuel cell. The air permit for this facility was originally issued in June 2001, and has been extended conditioned on revision of the BACT analysis. Construction of the facility has not begun.

Global Energy Lima Energy Power Station: Lima Energy Company, a Global Energy company, obtained a final Ohio EPA Permit to Install an IGCC facility in Lima, Ohio. The 540 MW (net) IGCC is expected to use entrained flow gasification technology to convert high sulfur coal or petroleum coke into synthesis gas. The air permit was issued in 2002, but construction of the IGCC plant has not yet begun.

We Energies Elm Road Generating Station: We Energies recently proposed a new 600 MW net nominal base-load IGCC generating unit at the Elm Road Generating Station. The facility includes a gasification plant, sulfuric acid plant, CTG and HRSG, and STG. The permit for this facility was received in January 2004. Construction of this facility is subject to a determination of need.

Table 5.5-1
Permitted Emission Rates for Syngas-Fired CTGs
In lbs/MMBtu Coal Heat Input (Approximate)

Location	MMBtu/hr to gasifier (estimated)	CO	NO_x	SO_2	PM	VOC
Wabash River	2,356	0.036	0.087	0.126	0.005	0.001
Polk Power Station	2,191	0.045	0.101	0.163	0.008	0.001
Kentucky Pioneer	4,413	0.026	0.059	0.026	0.009	0.004
Lima Energy	4,413	0.035	0.067	0.017	0.008	0.007
We Energies	5,424	0.024	0.059	0.023	0.008	0.003
Mesaba One	5,910	0.035	0.057	0.026	0.009	0.003

The emissions listed in Table 5.5-1 above have been estimated based on permit documents and converted to units of lbs per million Btu of gasifier feedstock, for purposes of general comparison. The actual permitted levels and/or BACT determinations, in many cases, is expressed in units different than lbs/MMBtu, and may be expressed on the basis of MMBtu input of syngas fuel to the CTGs instead of MMBtu to the gasifier (the correct basis). The proposed limits for the IGCC Power Station are quite similar to other recent IGCC permits.

5.6 Combustion Turbine Control Technology Review

The following BACT analysis evaluates each of the criteria pollutants emitted from the syngas-fired CTGs of the proposed IGCC Power Station to determine what is considered to be Best Available Control Technology. BACT today is based on the current state of technology, best engineering judgment, and current expected economics, energy, and other impacts.

5.6.1 Nitrogen Oxides BACT Analysis

NO_x is primarily formed in combustion processes in two ways: 1) the reaction of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x), and 2) the oxidation of nitrogen contained in the fuel (fuel NO_x). Syngas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is expected that essentially all NO_x emissions from the turbine originate as thermal NO_x.

IGCC is an inherently lower-emitting process that prevents emissions of NO_x at the high levels often seen in conventional PC power plants. Typical emissions from a new state-of-the-art PC plant utilizing selective catalytic reduction ("SCR") technology are in the range of 0.07 – 0.10 lb NO_x/MMBtu ("Environmental Impact Comparisons IGCC vs. PC Plants", Kahn, Wayland, and Schmidt of US EPA, presented at Pittsburgh Coal Conference, September 2005) while Mesaba One and Mesaba Two are expected to achieve 0.057 lb/MMBtu without add-on controls. Emissions from existing, well controlled PC plants without SCR can be as low as 0.15 lb/MMBtu (such plants would be likely to have installed low NO_x burners; staged combustion; overfire air; selective non-catalytic reduction technology; artificial intelligence burner control management systems; or a combination of such controls). Nonetheless, the BACT analysis considers the use of IGCC in conjunction with add-on controls that might further control and reduce emissions after they are produced.

The rate of formation of thermal NO_x is a function of residence time and the preponderance of oxygen radicals which increase exponentially with peak flame temperature. Front-end NO_x control techniques are aimed at controlling one or more of these variables during combustion. Examples include diluent injection (steam, water, or nitrogen) and dry low-NO_x burners. These technologies are considered pollution prevention techniques.

Other control methods utilize add-on control equipment to remove NO_x from the exhaust gas stream after its formation during the combustion process. The most common add-on control technique – SCR- involves the injection of NH_3 into the exhaust gas stream in the presence of a special catalyst, allowing the NO_x and NH_3 to react, forming molecular nitrogen and water.

5.6.1.1 Identify Control Technologies

Possible control technologies were identified through the examination of previous IGCC permits and through RBLC queries for natural gas-fired combined cycle CTGs. All previous BACT and LAER determinations for IGCC facilities have resulted in the best available controls for NO_x to be diluent injection. However, the BACT analyses for the IGCC CTGs evaluated all of the following technologies:

<u>Combustion Process Controls</u>

- Dry Low NO_x burners.
- Diluent injection.

<u>Post Combustion Controls</u>

- SCONO$_x$™
- SCR.
- Selective non-catalytic reduction (SNCR).

5.6.1.2 Evaluate Technical Feasibility

Each identified technology must be examined to determine if it is technically feasible for IGCC CTGs burning syngas, as follows:

5.6.1.2.1 Dry Low NOx Burners

Dry Low-NO_x (DLN) burners control NO_x formation in conventional natural gas-fired CTGs by staged combustion. This is done by designing the burners to control both the stoichiometry and temperature of combustion by tuning of the fuel and air locally within each individual burner's flame envelope. Burner design includes features that regulate the aerodynamic distribution and mixing of the fuel and air. A lean, pre-mixed burner design pre-mixes the fuel and air prior to combustion. This results in a homogeneous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean fuel-to-air ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers thermal NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

The existing DLN technology was designed for natural gas (methane-based) fuels and will not operate on syngas (hydrogen/CO-based) fueled IGCC turbines. DLN combustors are not technically feasible for this application due to the potential for explosive mixtures in the combustion section resulting primarily from the high hydrogen content of the syngas. Syngas differs from natural gas in heating value, gas composition, and flammability characteristics. Turbine vendors are currently researching DLN for syngas-fueled CTGs, but these combustors are not yet commercially available.

No manufacturer currently makes DLN burners that can be used for a CTG burning coal-derived syngas. Therefore, DLN burners are not deemed to be a technically feasible control option for the combustion turbines.

5.6.1.2.2 Diluent Injection

The addition of an inert diluent such as water or nitrogen into the syngas before combustion, and/or steam or nitrogen injection into the high temperature region of a combustor flame serves to minimize NO_x formation by reducing the peak flame temperature. Higher combustion temperatures may result in greater thermodynamic efficiency; however, higher temperatures also increase NO_x production. Syngas can be diluted with water or nitrogen (if available) while conditioning it for use in the CTG. This effectively lowers the combustion temperature, and therefore reduces NO_x emissions. Steam can also be injected directly into the combustion zone to cool temperatures and reduce NO_x formation. Diluent injection can achieve emission levels of 15 ppmvd NO_x (at 15 percent oxygen) when firing 100% syngas fuel. A secondary benefit of diluent injection is that it will increase the mass flow of the CTG exhaust and thereby increase power output.

During firing of the back-up fuel, natural gas, the diffusion flame burners will achieve 25 ppm NO_x. Diluent injection cannot achieve as low a NOx concentration on natural gas fuel as with syngas. However, natural gas is proposed for long-term use at a maximum of 5% of the time on an annual basis.

Diluent injection represents an inherently lower-emitting process for syngas-fired CTGs, and is a technically feasible control technology. Diluent injection, achieving NOx levels of 15 ppmvd (at 15% O_2) was considered as the baseline case for the CTG NO_x BACT analysis. This NO_x performance has also been determined as BACT for all other recent IGCC permits.

5.6.1.2.3 SCR

SCR is a process that involves post-combustion reduction of NO_x from flue gas with a catalytic reactor. An SCR system is composed of an ammonia storage tank, an injection grid (system of nozzles that spray NH_3 into the exhaust gas ductwork), and a reactor, which contains the catalyst, and instrumentation and electronic controls. This is an increasingly common control technology for use on natural gas-fired CTGs, but would have feasibility problems on a syngas-fired CTG system, as discussed later in this section.

In the SCR process, NH_3, usually diluted with air or steam, is injected through a grid system into the exhaust gas upstream of a catalyst bed. On the catalyst surface, the NH_3 reacts with NO_x to form molecular nitrogen and water. The basic reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$

$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$

A fixed bed catalytic reactor is typically used for SCR systems. The function of the catalyst is to lower the activation energy required for NO_x decomposition to occur. In natural gas service, NO_x removal of 90 percent and higher is theoretically achievable at optimum conditions. Removal efficiency is dependent on gas temperature, residence time, NO_x/NH_3 stoichiometry, and catalyst activity. Certain compounds such as sulfur and various metals, if present in the exhaust gas stream, will "poison" the catalyst, reducing its performance, useful life, and impact catalyst activity and/or conversion efficiency.

The typical effective temperature range for base-metal SCR catalysts is 600 – 800˚F. If the exhaust gas temperature drops below 600˚F, the reaction efficiency becomes too low and increased amounts of NO_x and NH_3 will be released into the atmosphere. HRSG exhaust temperatures are in the vicinity of 250˚F, and thus too low for the SCR reactions to occur. The catalyst must therefore be located within the HRSG where temperature conditions are favorable.

An environmental consideration in implementation of SCR is that while it will reduce NO_x emissions, operation of the SCR will add NH_3 emissions. A portion of the unreacted NH_3 passes through the catalyst and is emitted from the stack. This is called ammonia slip and is impacted by the catalyst activity and the degree of NO_x control desired.

A significant feasibility issue for the IGCC Power Station is the fact that the syngas contains sulfur and several other compounds that act as catalyst poisons. It is important to consider the ammonium sulfate and bisulfate problems unique to SCR use on a combined cycle CTG with sulfur-bearing fuels such as coal-derived syngas. The oxidation of sulfur present in the syngas fuel during combustion produces primarily SO_2 and also a small portion of SO_3. If SCR were installed, the vanadium in the SCR catalyst will oxidize additional amounts of the SO_2 in the flue gas to SO_3. Some of the NH_3 added to initiate the SCR process will react with the available SO_3 to form ammonium sulfate and bisulfate salts. These salts can cause serious corrosion and plugging/fouling problems in a conventional HRSG, as well as a loss of heat transfer. This is a serious concern, even at the relatively low levels of sulfur present in the syngas.

These ammonium salts would deposit onto heat transfer fins located inside the HRSG. As the exhaust gas passes over the heat transfer fins of the HRSG, ammonium sulfate and bisulfate condense from the gas and deposit directly onto the fins. The heat transfer efficiency of the fins gradually decreases as they become increasingly fouled with deposits. Power output from the turbine will also be significantly affected due to an increase in pressure drop within the HRSG resulting from the partial blockage of gas flow by these deposits. This pressure rise can also impact HRSG casing design requirements. In addition, ammonium bisulfate is corrosive and corrodes the heat transfer fins or tubes, impacting the reliability of the HRSG, and therefore the entire IGCC facility.

As deposits of ammonium salts increase, they would need to be cleaned from the surface of heat transfer fins in order to restore heat transfer efficiency and pressure within the HRSG. Adequate cleaning of the fins is difficult in a conventional HRSG due to the following:

- Access to interior tube banks in a HRSG is restricted.
- HRSG heat exchange elements are not designed for removal/replacement.
- The catalyst in a HRSG is in close proximity to areas that would need water washing, increasing the possibility of inadvertent wetting of the catalyst (which would cause damage).

In addition to the above-described sulfur/salting issue, another significant feasibility issue with syngas (vs. natural gas) is the potential presence of metals in syngas, which are known to deactivate the sensitive SCR catalyst. For example, SCR is impacted by compounds such as arsenic, even at levels significantly below those which might be health risk concerns. The concentrations of trace compounds such as arsenic, nickel, lead, cadmium, and other catalyst poisons makes it difficult to determine system performance, control efficiency, or catalyst life for this unique application.

There is a growing experience base of SCR on conventional PC units that might, on the surface, seem to suggest that SCR should work in the seemingly less extreme exhaust conditions of a syngas-fired CTG. However, there are key differences when compared to a PC plant SCR system application, including:

- SCR performance expectation in conventional PC unit service is significantly lower (i.e., higher outlet NO_x) than would be needed in the IGCC case. PC-based SCR systems typically achieve about 0.08 lb NO_x/MMBtu with SCR, which is greater than the IGCC Power Station’s proposed level (0.057 lb/MMBtu) without any add-on controls.

- Ammonium bisulfate salts would form in the PC plant’s air preheater, which is of a very different design from a HRSG and is well-suited to handling precipitation/deposits/ corrosion. Compared to a HRSG, a PC unit’s air preheater is designed for cleaning and replacement of components, and deposits do not significantly inhibit heat transfer as they would in a HRSG. Air preheater heat transfer baskets are not impacted as much by corrosion as the heat transfer fins in a HRSG.

- Ammonia preferentially adsorbs onto the fly ash produced from a PC unit, and sulfates and bisulfate can be captured in downstream particulate matter control equipment.

The technological, operational, and economic issues noted above dictate against any requirement to apply SCR to the IGCC Power Station. Significant additional testing and research on SCR in IGCC service is necessary to gain full understanding of and confidence in predicting system performance and cost determinations. EPA does not consider a technology “available” until it has reached commercial availability for its intended service. While SCR is clearly an “available” technology and commercially demonstrated for many applications, SCR is only at the "concept stage" for coal derived syngas-fired CTGs. The Applicant is unaware of any research or testing (at any scale) that has been done on this unique application, and should not be required to experience extended outages, significant costs, and extended trials to learn if this expensive control technology could be effectively utilized on this already environmentally superior source. EPA's New Source Review Workshop Manual (page 12, "New Source Review Workshop Manual" Draft 1990, EPA Office of Air Quality Planning and Standards) specifically states that "Technologies which have not been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice." On this basis, SCR technology is not commercially available for use as part of an IGCC power station using coal-derived syngas.

As described further in the SO_2 BACT section (Section 5.5.2), there are acid gas removal (AGR) technologies that can reduce the amount of sulfur in the syngas to levels (< 10 ppm) that might mitigate the concerns with sulfate salt plugging and corrosion. However, these physical solvents (Selexol and Rectisol) are extremely costly. In addition, SCR has still not been applied to coal-based IGCC power station even with deep sulfur removal.

In summary, SCR has never been employed at an IGCC facility using a solid feedstock such as coal or petroleum coke. This is primarily due to various feasibility, cost and operational concerns. The lack of SCR vendor guarantees is also an important factor in this consideration The question of SCR feasibility in IGCC service has been recently addressed by several other proposed projects and their state and regional environmental agencies. Polk Power Station in Florida, Kentucky Pioneer LLC in Kentucky, Lima Energy LLC in Ohio, and We Energies in Wisconsin have all finalized or updated BACT determinations for their IGCC projects. The state environmental agencies in Florida, Kentucky, Ohio, and Wisconsin, along with US EPA Region IV and Region V have determined BACT for those IGCC projects to be 15 ppm NO_x @15% O_2 using diluent injection. In each case, SCR was rejected as BACT.

Due to significant technical concerns and the lack of demonstrated commercial performance in IGCC service, SCR is judged to be commercially unavailable for this IGCC application. This finding is consistent with recent previous BACT determinations for syngas-fired CTGs that are part of IGCC facilities using solid feedstocks such as coal and/or petroleum coke.

5.6.1.2.4 SCONOx

The $SCONO_x$™ system is an add-on control device that reduces multiple pollutants. $SCONO_x$™ control technology is provided by Emerachem, LLC (formerly Goal Line Environmental Technologies). $SCONO_x$™ utilizes a single catalyst for the reduction of CO, VOC and NO_x and results in the emission of CO_2, H_2O and N_2. The system does not use NH_3 and operates most effectively at temperatures ranging from 300°F to 700°F. $SCONO_x$™ requires natural gas, water, steam, electricity and ambient air to operate, and no special chemicals or processes are necessary. Steam is used periodically to regenerate the catalyst bed and is an integral part of the process.

There are currently several $SCONO_x$™ units in commercial installations worldwide. All are operated on fairly small CTG facilities. The original installation is at the Federal Plant in Vernon, California owned by Sunlaw Cogeneration. This installation is on a GE LM2500, an approximately 25 MW combined cycle system, which has had an operating $SCONO_x$™ system since December 1996. That system has undergone many changes over the years. The second commissioning of a $SCONO_x$™ system was at the Genetics Institute in Massachusetts on a 5 MW Solar Turbine Model Taurus 50. This facility has reported problems with meeting permitted NO_x levels of 2.5 ppm and received a permit modification extending their $SCONO_x$™ demonstration period. Three other units were recently installed, two on 13 MW Solar Titan CTs at the University of California, San Diego, and one on an 8 MW Allison CTG at Los Angeles International airport.

There are no current $SCONO_x$ applications on large CTG units such as Mesaba One and Mesaba Two. Similarly, there are no applications with the sulfur levels of syngas-fired CTGs. $SCONO_x$™ was considered at some larger CTG applications including a 250 MW CTG at the La Paloma plant near Bakersfield, and a 510 MW plant in Otay Mesa. However, the La Paloma and Otay Mesa projects were given the alternative to install SCR and have done so. In evaluating technical feasibility of $SCONO_x$ for use in large IGCC power stations, the major concerns are as follows:

- $SCONO_x$™ uses a series of dampers to regenerate the catalyst. The IGCC Power Station is much larger than the smaller facilities where $SCONO_x$ has been used and would require a significant redesign of the damper system, which raises feasibility concerns regarding adequate operation of larger dampers.
- The catalyst is very susceptible to poisoning by sulfur compounds. Because of the sulfur content of the syngas, a catalyst to absorb SO_2 would be required. The vendor offers a $SCOSO_x$™ catalyst; however, its operation is not proven and it would create an H_2S stream that must be treated.
- $SCONO_x$™ would not be expected to achieve lower NOx levels than SCR, and it is anticipated to have the same feasibility concerns that were previously raised in connection with SCR.

For the above reasons, $SCONO_x$™ is considered technically infeasible for application to this large IGCC CTG.

5.6.1.2.5 SNCR

Selective Non-Catalytic Reduction (SNCR) is a post-combustion NO_x control technology in which a reagent (NH_3 or urea) is injected into the exhaust gases to react chemically with NO_x, forming nitrogen and water without the use of a catalyst. The success of this process in reducing NO_x emissions is highly dependent on the ability to uniformly mix the reagent into the flue gas. This must occur at a zone within the exhaust stream at which the flue gas temperature is within a narrow range, typically from 1,700°F to 2,000°F. In order to achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 seconds. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO_x.

Below the lower end of the temperature range, the reagent will not react with the NO_x and the NH_3 slip concentrations (NH_3 discharge from the stack) will be very high.

This technology is occasionally used in conventional fired heaters or boilers, but to the applicant's knowledge, it has never been applied in CTG service. This is primarily because there are no flue gas locations within the CTG or HRSG with the right temperature and residence times to allow use of SNCR technology.

Since SNCR has not been applied to any CTGs or IGCC units (according to the RBLC database and the applicant's permit review) and because of the incompatibility of the exhaust temperatures, SNCR is considered to be technically infeasible.

5.6.1.3 Rank Control Technologies

Diluent injection with a control level of 15 ppm NO_x was the only control technology determined to be technically feasible and commercially available for an IGCC application. Table 5.6-1 below shows this control option versus the NSPS Subpart Da emissions level that is considered the BACT "floor" for this source category.

It should be noted that during firing of the back-up fuel, natural gas, the diffusion flame burners will achieve 25 ppm NO_x. The Applicant proposes to use natural gas for less than 440 hours per year on a long-term basis. Therefore, the annual emissions estimates for diluent injection include NO_x at the higher rate for 440 hours per year, with the balance of the year firing syngas at the lower NO_x emission rate of 15 ppmvd at 15% oxygen.

Table 5.6-1
Ranking Of NO_X Control Technologies

Control Technology Option	Uncontrolled Emissions	Emissions Reduction	Emissions Achievable	Annual Emissions per IGCC CTG[1]
Nitrogen/Steam Injection	N/A	N/A	0.0566 lb/MMBtu	693 TPY
NSPS Subpart Da Proposed Limit	N/A	N/A	1.0 lb/MWh (~ 0.11 lb/MMBtu)	~1,050 TPY

Notes: Annual emissions are based on one CTG firing 440 hours per year on natural gas at 25 ppmvd, and the balance on syngas at the 15 ppmvd level at full load. (Mesaba One and Mesaba Two include 4 CTGs total.)

5.6.1.4 Evaluate Control Options

The next step in the BACT process is to conduct an analysis of the energy, environmental and economic impacts associated with each feasible control technology. Based on the previous evaluation, the applicant believes that the only technically feasible and available technology for IGCC Power Station is diluent injection in the CTG, which has no negative energy or environmental impacts.

5.6.1.5 Select Control Technologies

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As has been explained, for this unique application of a syngas-fired CTG as part of the IGCC facility, diluent injection in the CTG is chosen as BACT. This technology will achieve an emission rate of 15 ppm NO_x at 15% O_2 for syngas firing, and 25 ppm NO_x at 15% O_2 for natural gas firing.

The BACT selection of diluent injection to the NO_x levels described above is strongly supported by recent precedent for similar IGCC projects. Diluent injection was designated as LAER for an IGCC turbine project in Delaware (Motiva/Star Enterprises), as BACT for three proposed IGCC projects in Wisconsin (We Energies), Kentucky and Ohio (Global Energy) and as BACT in a BACT re-evaluation of an existing IGCC in Florida (Tampa Electric).

Add-on controls such as SCR and SCONO$_x$™ have been determined to have significant problems regarding the technical feasibility of their application to IGCC CTGs, and are not commercially demonstrated or available for such an application. IGCC is an inherently lower-polluting technology, and should not be burdened with the additional costs and technical uncertainties of add-on pollution control technologies for NO_x. Therefore, diluent injection is the most stringent and technically feasible control technology, and is the best available option. As such, the applicant proposes that NO_x BACT is 15 ppmvd @ 15% O_2, or 157 lb/hr per CTG stack, when firing syngas.

5.6.2 Sulfur Dioxide and Sulfuric Acid Mist BACT Analysis

5.6.2.1 Identify Control Technologies

The combustion of syngas in the CTG creates SO_2 and sulfur trioxide (SO_3) by the oxidation of the sulfur species in the fuel. The vast majority of the sulfur forms SO_2. A small percentage of the sulfur forms SO_3, which combines with the moisture in the exhaust to form sulfuric acid mist, or H_2SO_4. Sulfur emissions from any combustion process are directly related to the sulfur content of the fuel being combusted. Emissions can be controlled either by limiting the sulfur content of the fuel (pre-combustion control) or by scrubbing the SO_2 from the exhaust gas (post-combustion control). Possible control technologies include:

<u>Pre-Combustion Process Controls</u>

- Chemical Absorption Acid Gas Removal (AGR).
- Physical Absorption AGR.

<u>Post-Combustion Controls</u>

- Flue Gas Desulfurization (FGD).

5.6.2.1.1 Acid Gas Removal (AGR)

Sulfur in the feedstock converts to either H_2S or COS in the gasification process. A COS hydrolysis unit is provided to achieve a high level of sulfur removal. The COS is converted to

H_2S, which is more efficiently removed in the AGR system. Solvent-based acid gas cleanup is commonly used for "gas sweetening" processes in refinery fuel gas or tail gas treatment settings where H_2S in the process gas may be treated before use as a fuel or released to the atmosphere. The removed H_2S is then recovered either as elemental sulfur in a SRU or converted to H_2SO_4 in a sulfuric acid plant.

AGR systems can employ either chemical absorption or physical absorption methods. Chemical absorption occurs in amine-based systems that use solvents such as methyl diethanolamine (MDEA). Amine solvents chemically bond with the H_2S. The H_2S can be easily liberated with low-level heat in a stripper to regenerate the solvent. This is the technology that has been used in all existing and recently-permitted IGCCs, and is considered the base level of control for an IGCC facility.

Alternate AGR systems include those utilizing a physical absorption solvent such as methanol (Rectisol) or mixtures of dimethyl ethers of polyethylene glycol (Selexol). When using physical solvents, the H_2S is dissolved under pressure into the solvent. Dissolved acid gases can be removed by depressurization to regenerate the solvent for reuse. Physical absorption methods have been used to purify gas streams in the chemical processing and natural gas industries. However, physical absorption has not been used to remove H_2S from syngas at a solid fuel based IGCC power station.

5.6.2.1.2 Flue Gas Desulfurization

A FGD application usually operates by contacting the exhaust gas with an alkaline slurry or solution that absorbs and subsequently reacts with the acidic SO_2. FGD technologies may be wet, semi-dry, or dry based on the state of the reagent as it is injected or pumped into the absorber vessel. Also, the reagent may be regenerable (where it is treated and reused) or non-regenerable (all waste streams are de-watered and either discarded or sold). Wet, calcium-based processes, which use lime (CaO) or limestone ($CaCO_3$) as the alkaline reagent, are the most common FGD processes in PC unit applications. After the exhaust gas has been scrubbed, it is passed through a mist eliminator and exhausted to the atmosphere through a stack

FGD systems are commonly employed in conventional PC plants where the level of sulfur emissions in the exhaust is relatively high, and can achieve >95% reduction.

5.6.2.2 Evaluate Technical Feasibility

Both chemical and physical absorption methods for AGR are considered potentially feasible for an IGCC application and are further considered in this analysis. FGD does not provide a higher level of control than the pre-combustion AGR systems, and is not considered a reasonable technical option for IGCC. Since the sulfur would be removed more efficiently and economically from syngas prior to combustion in the CTGs, it is concluded that FGD will not be considered further in this BACT analysis.

5.6.2.3 Rank Control Technologies

Technically feasible control technologies are summarized in Table 5.6-2 in ascending order of control efficiency. Emissions in pounds per million Btu of coal and annual emissions for each of four combustion turbines are also shown along with uncontrolled and NSPS emissions for comparison.

Table 5.6-2
SO_2 Control Technology Options

Control Technology Option	Control Efficiency	SO_2 Emissions (lb/MMBtu)	Annual SO_2 Emissions (one CTG)	Emissions Reduction with Ill. No. 6 Coal (tons/yr, 1 CTG)
Uncontrolled	-	5.0	66,662 tons	-
Proposed NSPS Da	95.8%	~0.21	2,800 tons	63,862 tons
Chemical Solvent AGR (MDEA – Base IGCC Level)	99.5%	0.026	333 tons	66,329 tons
Physical Solvent AGR (Selexol)	>99.8 %	0.01	133 tons	66,529 tons

5.6.2.4 Evaluate Control Options

The syngas initially produced will contain as much as 10,000 ppm sulfur (assuming the IGCC Power Station's worst case feedstock) primarily in the form of H_2S. In an IGCC process, the sulfur in the syngas can be reduced dramatically and relatively easily prior to combustion of syngas in the CTGs. Chemical absorption processes such as AGR with MDEA have been used in all existing and permitted IGCC facilities, and are therefore considered the base level of control for IGCC. This removal of sulfur in a chemical process prior to combustion is part of what makes IGCC an inherently-lower polluting technology.

The most effective SO_2 control system that is considered to be technically feasible is the physical absorption AGR system. The second most effective SO_2 control option is the base IGCC level of amine (MDEA) chemical absorption AGR system. Both of these options are evaluated in the economic analysis below.

The MDEA system is typical for IGCC units, and is currently considered the optimum level of control for this application of gasification-polluting technology. The costs per gasifier train for adding a Selexol physical absorption AGR system were estimated and are shown below at Table 5.6-3. The Selexol system is considerably more expensive than a conventional amine-based AGR, and also results in an unacceptable economic penalty on plant performance of 2 %, or 12 MW for the Phase 1 IGCC Power Station, and a 4% penalty for the Phase I and II Power Station. These energy costs are included in the annual operating costs shown in Table 5.6-3.

Table 5.6-3
Cost Comparison for SO_2 Control Technology

Control Technology	Capital Investment*	Annual Operating Costs	Total Annual Costs	Incremental Tons SO_2 Reduced	Cost Effectiveness ($/ton)
Physical Solvent AGR (Selexol)	$22,200,000	$2,600,000	$5,000,000	200	$25,200
Chemical Solvent AGR (MDEA)	*N/A – Base level of control for IGCC*				

*2Q 2005 cost estimate basis

As is illustrated in Table 5.6-3 above, a Selexol system will cost approximately $20 million in additional capital costs and over $2.5 million in additional annual operating costs (per combustion turbine), while only reducing an additional 200 tons per year of SO_2. This results in a removal cost of $25,000 per additional ton of SO_2 reduced, an amount which the Applicant believes to be prohibitively expensive.

5.6.2.5 Select Control Technologies

The applicant proposes that SO_2 emissions from the CTGs will be minimized through treatment of the syngas with MDEA, which will remove greater than 99% of sulfur in the syngas when using Illinois No. 6 bituminous coal; for PRB sub-bituminous coals the removal of sulfur from syngas is expected to be greater than 97 percent. The syngas sulfur content will be reduced to less than 50 ppmvd as hydrogen sulfide in the undiluted syngas on a 30-day rolling average basis. Syngas at this reduced level of sulfur will result in CTG SO_2 emissions of less than 0.026 lb/MMBtu and sulfuric acid mist emissions of less than 0.0026 lb/MMBtu (See Section 2.2.4 for additional details on the proposed process).

Additional SO_2 reductions that could be achievable through a physical absorption AGR method are too costly and represent an economic burden for consumers.

The IGCC Power Station's emission rates are extremely low when compared to SO_2 emissions BACT determinations for recent PC units that average 0.25 lb/MMBtu, and the proposed NSPS for PC boilers which requires 2.0 lb/MWh, or approximately 0.21 lb/MMBtu. This is one of the major environmental advantages of IGCC technology. The proposed level of syngas treatment to 50 ppmvd maximum H_2S concentration in the undiluted syngas is, for perspective, significantly below the stringent NSPS Subpart J allowed concentration (160 ppm) for new petroleum refinery combustion devices. The Applicant proposes that cleaning the syngas to 50 ppmvd sulfur content (expressed as H_2S in the undiluted syngas) is BACT for SO_2 and sulfuric acid mist for the CTG/HRSG exhaust. This corresponds to approximately 5 ppm SO_2 and 76 lb SO_2/hr for each CTG exhaust.

5.6.3 Volatile Organic Compound BACT Analysis

VOCs are a product of incomplete combustion of the organic fuel. Reduction of VOC emissions is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion.

The primary technologies identified for reducing VOC emissions from the CTGs are oxidation catalysts and good combustion controls. A survey of the RBLC database indicates that good combustion control and burning clean gas fuel are the VOC control technologies primarily determined to be BACT. Additionally applicable to the IGCC technology is the fact that it uses a very low VOC fuel, syngas, which when burned yields very low levels of uncombusted VOC emissions.

5.6.3.1 Identify Control Technologies

Three technologies were identified as potentially applicable to the IGCC Power Station's CTGs for control of VOC emissions:

Combustion Process Controls

- IGCC technology (use of low VOC syngas)
- Good Combustion Practices (GCP)

Post Combustion Controls

- Oxidation Catalysts

5.6.3.2 Evaluate Technical Feasibility

Each identified technology is examined to determine if it is technically feasible for IGCC turbines burning syngas.

5.6.3.3 Rank Control Technologies

Combustion of any hydrocarbon material can produce trace levels of uncombusted VOCs. Combustion of fuels with very low hydrocarbon content can lower these VOC emissions. The very nature of the IGCC process leads to unusually low levels of organic emissions from syngas combustion.

The gasification process involves feeding a slurry of carbon-containing materials into a heated and pressurized chamber (the gasifier) along with a controlled and limited amount of oxygen. At the extremely high operating temperatures and pressures in the gasifier, chemical bonds are broken by oxidation and steam at temperatures sufficiently high to promote very rapid reactions. The various constituents that are in the feedstock are broken down into their fundamental elements in the gasifier, and are reformed into the syngas composed primarily of diatomic hydrogen (H_2) and CO gas. Very few hydrocarbons are left unreacted. The VOC content of the clean syngas is estimated to contain less than 0.1% VOC (this is the concentration of VOCs before being burned in the CTG). These compounds are efficiently burned in the CTG to create water (H_2O) and carbon dioxide (CO_2). Emissions of VOCs are expected to be a small fraction of the level that would be emitted from conventional gas-fired CTGs.

5.6.3.3.1 Good Combustion Practices

Good combustion practices (GCPs) applied to the proposed sources can achieve VOC emission levels of 2.4 ppmvd (at 15 percent O_2) as reflected in current supplier quotations. GCPs include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure that there is sufficient oxygen present for complete combustion. This is the technology option used as BACT for all other recent IGCC permits.

5.6.3.3.2 Oxidation Catalyst

Catalytic oxidation is a post-combustion technology where the products of combustion are introduced to a catalytic bed at the appropriate temperature point in the HRSG. The catalyst promotes the oxidation of VOC. The catalyst beds that reduce CO can also be effective in reducing VOC emissions. However, such systems typically achieve a maximum efficiency of 50 percent. Oxidation catalyst vendors declined to quote a system due to the presence of low sulfur levels in the exhaust as further described in the CO BACT evaluation. Oxidation catalysts have never been used on coal-based combustion systems. For these reasons, catalytic oxidation is not considered a practical or feasible technology for this IGCC application.

It is also worth noting that a typical additional incentive, when feasible, to using an oxidation catalyst is the incidental control of organic HAPs. For example, uncontrolled formaldehyde (CHOH) emissions can be fairly significant from conventional combustion of natural gas (CH_4). However, since syngas contains primarily H_2 and CO with less than 0.1% VOCs, uncontrolled emissions of formaldehyde, or other organic HAP emissions, are significantly less. For this reason, an oxidation catalyst, even if feasible, would provide less benefit for a syngas-fired CTG versus a natural gas-fired CTG.

5.6.3.4 Evaluate Control Options

Catalytic oxidation is an infeasible method of controlling VOC emissions from the proposed CTGs. The only feasible alternatives are use of low VOC fuel and GCPs.

5.6.3.5 Select Control Technologies

The recommended control of VOC emissions from each of the proposed turbines is use of the IGCC process (low VOC fuel) and GCPs at the CTG. These practices will meet a VOC emission limit of 9 lb/hr/CTG while operating under steady state conditions and firing syngas. The Applicant concludes that VOC BACT is 9 lb/hr/CTG using these practices.

5.6.4 Carbon Monoxide BACT Analysis

CO is a product resulting from incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors, however, can also tend to result in increased emissions of NO_x. Conversely, a lower NO_x emission rate achieved through flame temperature control (by diluent injection or dry lean pre-mix) can sometimes result in higher levels of CO emissions. Thus, a balancing of these conditions is necessary so that the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping CO emissions to an acceptable level.

CO emissions from CTGs are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Possible post-combustion control involves the use of catalytic oxidation while front-end control involves controlling the combustion process to suppress CO formation.

5.6.4.1 *Identify Control Technologies*

Three technologies were identified as potentially applicable to the IGCC Power Station's CTGs for control of CO emissions:

Combustion Process Controls

- GCPs

Post Combustion Controls

- $SCONO_x$™
- Oxidation Catalyst

5.6.4.2 *Evaluate Technical Feasibility*

Each identified technology is examined to determine if it is technically feasible for IGCC CTGs burning syngas.

5.6.4.2.1 SCONOx™ System

The $SCONO_x$™ system was described in the BACT analysis for NO_x. It is commercially available for small frame CTGs for controlling CO and can reduce emissions by up to 95 percent. However, it is not commercially available for large frame turbines (like those to be used for Mesaba One and Mesaba Two) for the same reasons set forth in the NO_x BACT discussion. Therefore, $SCONO_x$™ is considered to be technically infeasible for the IGCC Power Station.

5.6.4.2.2 Oxidation Catalysts

Oxidation catalysts are a post-combustion technology which do not rely on the introduction of additional chemicals, such as NH_3 with SCR, for a reaction to occur. They have occasionally been permitted for use in CTG applications when natural gas fuel is used. The oxidation of CO to CO_2 utilizes excess air present in the CTG exhaust and the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. At higher temperatures, catalyst sintering may occur, potentially causing permanent damage to the catalyst. The addition of a catalyst bed onto the turbine exhaust will create a pressure drop, resulting in back pressure to the turbine. This has the effect of reducing the efficiency of the CTG and power generating capabilities.

By placing the catalyst at a selected position within the HRSG, the temperature can fall within the parameters appropriate for CO catalytic oxidation. However, the applicant believes that the same feasibility issues described in the NO_x SCR catalyst will exist with a CO oxidation catalyst.

Additionally, as previously mentioned, an additional potential incentive to using a CO oxidation catalyst would be the incidental control of VOC and organic HAPs. However, as discussed in the VOC BACT section, because syngas has a very low VOC content, the uncontrolled emissions of VOC and organic HAPs from a syngas-fired CTG are already much lower than conventional CTG exhausts.

5.6.4.2.3 Combustion Control

GCPs include operational and boiler design elements to control the amount and distribution of excess air in the flue gas to ensure that there is sufficient oxygen present for complete combustion. Such control practices applied to the proposed CTGs can achieve CO emission levels of 15 ppm during steady state, full load operation. It should be noted that at lower loads (<50-70%), CTG combustion efficiency drops off notably, and resulting CO emissions would be higher. However, since the proposed IGCC Power Station will operate above this minimum load except during startup and shutdown, low load conditions are not appropriate as the basis of the BACT analysis.

GCPs are a technically feasible method of controlling CO emissions from the proposed CTGs.

5.6.4.3 *Rank Control Technologies*

The only technically feasible CO control technology is GCPs as presented in Table 5.6-4.

Table 5.6-4
Ranking Of CO Control Technologies

Control Technology	Removal Efficiency Range (%)	Controlled Emission Level (ppm)
GCPs	Not Applicable (baseline)	15

5.6.4.4 *Evaluate Control Options*

GCP is considered the baseline and only feasible control technology. Additionally, it has been selected as BACT for all other recent IGCC permits.

5.6.4.5 *Select Control Technologies*

GCPs is the only technology that is both technically and economically feasible at this time. the Applicant concludes that CO BACT is 15 ppmvd @ 15 percent O_2 (loads > 50-70%) using GCPs.

5.6.5 Particulate Matter BACT Analysis

Particulate matter emissions from natural gas-fired combustion sources consist of inert contaminants in natural gas, sulfates from fuel sulfur, dust drawn in from the ambient air that passes through the CTG inlet air filters, and particles of carbon and hydrocarbons resulting from incomplete combustion. Generating units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate matter emissions. Clean gaseous fuel, such as syngas, will also be low emitting. The hot raw syngas exiting the gasifier is cooled and sent to a filter system for particulate matter removal prior to other gas treatment systems such as scrubbing and AGR. This filter system contains a hot gas cyclone and a particulate matter filter that uses numerous porous filter elements to remove PM/PM_{10}, and is expected to achieve 99.9% removal efficiency.

The EPA has indicated that particulate matter control devices are not typically installed on CTGs and that the cost of installing a particulate matter control device is prohibitive (EPA, September 1977). When the NSPS for Stationary Gas Turbines (40 C.F.R. 60 Subpart GG) was promulgated in 1979, the EPA indicated that, "Particulate emissions from stationary gas turbines are minimal." Therefore, performance standards for particulate matter control of stationary gas turbines were not proposed or promulgated.

Post combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial gas-based CTGs. Therefore, the use of ESPs and baghouses is considered technically infeasible, and does not represent feasible control technology.

In the absence of add-on controls, the most effective control method demonstrated for CTGs is the use of low ash fuel, such as natural gas or syngas. This was confirmed by a survey of the RBLC database which showed no add-on PM/PM_{10} control technologies for combined-cycle CTG units. Proper combustion control and the firing of fuels with negligible or zero ash content (such as natural gas or syngas) is the predominant control method listed.

The use of clean syngas fuel and good combustion control is concluded to represent BACT for PM/PM_{10} control in the proposed turbines. These operational controls will limit PM/PM_{10} emissions to approximately 25 lb/hr per CTG when operating on syngas.

5.7 Tank Vent Boiler Control Technology Review

The tank vent boiler (TVB) is a combustion device that has a nominal 65 MMBtu/hr firing capacity. It will combust streams from various in-process storage tanks that may contain small amounts of sulfur, creating potential SO_2 emissions. Additionally, the process streams may contain other components similar to syngas, creating a unique fuel stream that is unlike any found for permitted combustors in the RBLC database. For this reason, pollutant emissions are addressed on an individual basis and compared to existing facilities where appropriate. The combustor emissions are largely dependent on burner specifications for this unique fuel.

5.7.1 Nitrogen Oxides BACT Analysis

In order to achieve adequate destruction efficiencies, the TVB requires a relatively high combustion flame temperature and residence time, both of which are fundamentally incompatible with low NO_x burner technology. Dry low NO_x burners are considered technically infeasible for this reason.

SCR is not an economically feasible control option for installation on a 65 MMBtu/hr boiler. Using SCR cost data in a 2001 EPA report regarding BACT for oil refinery gas-fired heaters (US EPA Report "Petroleum Refinery Tier 2 BACT Analysis Report, Final Report," January 16, 2001, prepared by ERG, Morrisville NC), the applicant conservatively estimates that an SCR system for this small source, even if technically feasible, would have annualized costs of over $75,000/yr. Even if it controlled 80% of the NO_x (to 7 ppmvd @ 3% O_2), the cost-effectiveness would be greater than $13,000/ton of NO_x controlled, which is deemed to be prohibitively expensive.

Burner design is specified by the vendor to accommodate this unique process fuel stream. No add-on combustion controls are technically feasible. BACT for this unique application is proposed at 0.3 lb NO_x/MMBtu.

5.7.2 Sulfur Dioxide BACT Analysis

For the same reasons given for the CTG exhaust in Section 5.5.2, applicant proposes that cleaning the synthesis gas to 50 ppmvd sulfur content (expressed as H_2S in the undiluted syngas) is BACT for SO_2 for the tank vent boiler exhaust.

5.7.3 Volatile Organic Compound BACT Analysis

VOCs are a product of incomplete combustion in the tank vent boiler. Recent BACT determinations for facilities permitted in Minnesota with small (< 100 MMBtu/hr) natural gas- or fuel oil-fired boilers had the requirements listed in Table 5.7-1.

Table 5.7-1
Recent VOC BACT Requirements for Comparable Minnesota Facilities

Facility	Fuel Fired	Capacity (MMBtu/hr)	VOC BACT Limit lb/MMBtu	Control Requirement
Fairbault Energy Park (7/15/2004)	Natural Gas	40	0.006	Good combustion
Fairbault Energy Park (7/15/2004)	#2 Fuel Oil	40	0.003	Good combustion
Mankato Energy Center (9/29/2004)	Natural Gas	70	0.007	Good combustion

VOC emissions from the tank vent boiler will be minimized by utilizing good combustion practices (GCPs) and achieving high combustion efficiency. BACT for VOC is proposed at 0.004 lb/MMBtu through the use of GCPs.

5.7.4 Carbon Monoxide BACT Analysis

Recent BACT determinations for facilities permitted in Minnesota with small (< 100 MMBtu/hr) natural gas- or fuel oil-fired boilers had the requirements listed in Table 5.7-2.

Table 5.7-2
Recent CO BACT Requirements for Comparable Minnesota Facilities

Facility	Fuel Fired	Capacity (MMBtu/hr)	CO BACT Limit lb/MMBtu	Control Requirement
Fairbault Energy Park (7/15/2004)	Natural Gas	40	0.084	Good combustion
Fairbault Energy Park (7/15/2004)	#2 Fuel Oil	40	0.036	Good combustion
Mankato Energy Center (9/29/2004)	Natural Gas	70	0.06	Good combustion

CO emissions from the tank vent boiler will be minimized by utilizing GCPs and achieving a high combustion efficiency. BACT for CO for the unique application within which the TVB is used is proposed at 0.09 lb/MMBtu through the use of GCPs.

5.7.5 Particulate Matter BACT Analysis

Recent BACT determinations for natural gas- or fule oil-fired boilers similar in size to the TVB permitted in Minnesota had the requirements listed in Table 5.7-3.

Table 5.7-3
Recent PM BACT Requirements for Comparable Minnesota Facilities

Facility	Fuel Fired	Capacity (MMBtu/hr)	PM BACT Limit lb/MMBtu	Control Requirement
Fairbault Energy Park (7/15/2004)	Natural Gas	40	0.008	Clean fuel and good combustion
Fairbault Energy Park (7/15/2004)	#2 Fuel Oil	40	.024	Clean fuel and good combustion
Mankato Energy Center (9/29/2004)	Natural Gas	70	0.008	Clean fuels

PM/PM_{10} emissions from the tank vent boiler will be minimized by utilizing GCPs and firing inherently low ash fuels. BACT for PM/PM_{10} is proposed at 0.01 lb/MMBtu through the use of GCPs.

5.8 Flare Control Technology Review

Venting to the flare will occur during startup or short-term combustion turbine outages. The gasifier system can be shut down rapidly through removal of slurry and oxygen injection, which provides isolation of the gasifier. This will avoid a flare or vent release of raw, untreated syngas. Therefore, potential emissions are estimated to be negligible.

5.8.1 Nitrogen Oxides BACT Analysis

The majority of BACT determinations in the RBLC database (see Appendix EI) show no controls required with emissions at or below 0.064 lb/MMBtu, the proposed NO_x emission rate. Good flare design is considered BACT for this level of emissions.

5.8.2 Sulfur Dioxide and Sulfuric Acid Mist BACT Analysis

SO_2 emissions are minimized from the pilot flame by the use of clean natural gas as the pilot. In addition, syngas sent to the flare during plant startup events will be treated in the AGR system, significantly reducing emissions. Given the negligible emissions, no control technologies are deemed to be cost effective.

5.8.3 Volatile Organic Compound, Carbon Monoxide, and Particulate BACT Analysis

As a product of combustion, CO and VOC will be emitted from the flare. Good flare design and GCPs will limit these CO emissions. Given minimal emissions, no control technologies are deemed to be cost effective.

5.9 Fugitive Equipment Leak Technology Review

Potential control methods for fugitive equipment leaks include typical "good work practices" (GWPs) where leaks are repaired soon after discovery and piping and equipment are maintained in good condition pursuant to an established Leak Detection and Repair (LDAR) program consisting of a structured program of inspection, monitoring, and repair. An LDAR program would be the top control alternative.

IGCC facilities do not have any permitted requirements for fugitive equipment leaks of VOC emissions because of the very low VOC levels in the process streams. Similarly, applicant proposes that GWPs are BACT for minimizing VOC emissions from fugitive equipment leaks.

5.10 Material Handling Technology Review

Mesaba One and Mesaba Two will employ multiple material handling activities for coal, petroleum coke, flux, and slag (see Section 4.1.5). These activities are similar to those found at facilities with coal-fired boilers. The types of activities and proposed BACT control technologies are summarized in the Table 5.10-1.

Table 5.10-1
IGCC Power Station Proposed BACT Activities

IGCC Power Station Facility	Processing Activity	BACT Control Technology	% Reduction
Coal Handling and Storage	Railcar Unloading	Partial Enclosure/ dust suppression	75
	Unloading hopper to Unloading Conveyor	Full Enclosure/ dust suppression	95
	Unloading conveyor to Cross-conveyor	Full Enclosure/ dust suppression	95
	Cross-conveyor to Stacker Conveyor	Full Enclosure/ dust suppression	95
	Stacker Conveyor to Stacker	Full Enclosure/ dust suppression	95
	Stacker to Coal Pile	Dust suppression/ adjustable stacker	50
	Reclaimer to Reclaim Conveyor	Partial Enclosure/ dust suppression	75
	Reclaim Conveyor to Main Conveyor	Full Enclosure/ dust suppression	95
	Main Conveyor to Incline Conveyor	Full Enclosure/ dust suppression	95
	Incline Conveyor to Tripper Conveyor	Full Enclosure/ dust suppression	95
	Tripper Conveyor to Feed Bin	Full Enclosure/ baghouse	99
	Windage from Coal Storage	None	0
Coal Slurry Facility Sources	Feed Bin to Weigh Belt Feeder	Full Enclosure/ dust suppression	95
	Weigh Belt Feeder to Rod Mill Feed Chute	Full Enclosure/ dust suppression	95
Slag Transport and Storage	Slag Disposal Truck Traffic	Dust suppression	80
	Slag Storage Load-in	Wet slag	100
	Windage from Slag Storage	None	0
	Slag Storage Load-out	None	0

Material handling of various raw materials and byproducts creates fugitive particulate emissions. Fugitive dust emissions may be controlled by one of the following methods (Source: EPA 450/3-81-005b (September 1982), Environmental Progress (February 1984)):

- Total enclosure with ventilation to a fabric filter
- A partial enclosure
- A water spray system
- A wet suppression system using water and chemical wetting agents

In general, BACT for material handling activities such as those at the Mesaba Plant consists of applying one of the control measures above at least at the partial enclosure, or 70% control, level. The ‘stacker to coal pile’ coal handling activity is a unique activity that uses partial containment at a 50% reduction. This is the most appropriate control technology for this activity.

Those activities that do not have any proposed additional control measures have potential (uncontrolled) emissions less than 0.5 tons TSP per year. Additional control measures applied to such small emitters would not be cost effective. Total proposed (controlled) emissions are less than 5 tons TSP and less than 2 TPY PM_{10} per year for all material handling activities for Phase I of the project. Phase II will be comprised of the same activities and same proposed controls, with the same total emissions as Phase I.

5.11 Cooling Tower Technology Review

Dissolved solids are emitted from the cooling towers in fine droplets of water entrained (carried) with the high air flows in the tower needed for the evaporative cooling process (commonly referred to as cooling tower drift). These droplets often fall very close to the tower. The cooling towers for the IGCC Power Station would employ high efficiency mist eliminators that will minimize drift from the cooling towers. The design drift rate will be less than 0.001% of the circulating cooling water flow. This design parameter along with the estimated emission rate meets or exceeds the majority of BACT determinations for cooling towers in the EPA RBLC database records (see Appendix EI for the last five years of RBLC determinations) as well as for similar recently permitted Minnesota facilities. Therefore, this technology represents BACT for cooling towers to minimize particulate matter emissions through minimizing drift rates.

5.12 Diesel Engine Technology Review

The fire water pump and emergency generators will be run by diesel engines and will be a source of emissions from combustion due to firing diesel fuel oil. Fire water pump operation will be voluntarily limited to 100 hours per year per engine. According to the EPA's draft Alternative Control Techniques (ACT) Document NO_x Emissions from Reciprocating Internal Combustion Engines (EPA-453/R-93-032, 1996) and the RBLC database records for BACT determinations of diesel engines for the years 2000 – 2005, there are no add-on controls that provide cost effective reductions. BACT for all criteria pollutants is represented by GCPs, limited hours of operation, and the use of low sulfur diesel fuel.

5.13 Auxiliary Boiler Technology Review

The natural gas-fired auxiliary boiler will be rated at approximately 130 MMBtu/hr and will only operate when there is not steam available from the gasifiers or HRSGs. It is therefore expected to operate less than 25% of maximum capacity each year. Natural gas will be the only fuel used, and emissions of NO_x, CO, SO_2, PM_{10}, and VOC will be generated.

The RBLC database pertaining to large (>100 MMBtu/hr) natural gas-fired boilers was reviewed for potential control technologies, and indicates that low-NO_x burners have been the most prevalent control applied over the past five years. Table 5.13-1 below summarizes the requirements of five similar facilities having natural gas-fired auxiliary boilers with throughputs of approximately 130 MMBtu/hr.

Table 5.13-1
Recent BACT Requirements for Comparable Facilities

Facility	Fuel Fired	Capacity (MMBtu/hr)	BACT Limit (lb/MMBtu)					Control Requirement
			NO_x	CO	PM_{10}	SO_2	VOC	
Rebud Power Plant (October 2002- OK)	Natural Gas	120	0.049	0.082	0.007	6E-04	0.005	GCP, Low NO_x Burners
Tenaska Arkensas Partners, LP (October 2001- AR)	Natural Gas	122	0.040	0.110	0.005	0.006	0.004	GCP, FGR, Fuel Specification: NG
Rocky Mountain Energy Center, LLC (September 2003- CO)	Natural Gas	129	0.038	0.039				GCP, Low NO_x burners. Limited hours of operation
PSEG Lawrenceburg Energy Facility (December 2002- IN)	Natural Gas	124.6	0.036	0.082	0.928	0.006	0.0054	GCP, Low NO_x burners, Fuel Specification: NG
AES Red Oak LLC (November 2003- NJ)	Natural Gas	120	0.036					GCP, Fuel Specification: NG, Limited hours of operation

Based on a review of similar natural-gas fired boilers, the only control technology determined to be technically feasible and commercially available for an IGCC application of auxiliary boilers was the use of combustion controls. Combustion controls will ensure essentially complete combustion, and minimize emissions of NO_x, CO, and VOC. Use of only natural gas as a fuel will minimize emissions of PM and SO_2.

BACT proposed for the IGCC auxiliary boiler is therefore proposed as:

- Exclusive use of natural gas as the fuel type
- Low NO_x Burners
- Good combustion practices

6. PHYSICAL, METEOROLOGICAL, AND AIR QUALITY CHARACTERISTICS OF THE IGCC POWER STATION FOOTPRINT AND BUFFER LAND

6.1 Land Use and Topography

The IGCC Power Station Footprint and Buffer Land includes approximately 1,260 acres of mostly undeveloped property. The land cover on and adjacent to the IGCC Power Station Footprint and Buffer Land include forest lands consisting of coniferous forest, mixed wood forest and regeneration/young forests; wetland areas; and scattered areas of grassland. Portions of the Site are presently used for timber production. Two high voltage transmission line corridors intersect within the Site boundary facilitating use by local sport enthusiasts for hunting or all terrain vehicle touring.

Regionally, the same land cover and land uses are prevalent where neither open pit mines nor rural residences are located. The northern boundary of the City of Taconite is located 1300 feet south of the IGCC Power Station Footprint and Buffer Land with the density of residential development around the Site being low. Residential developments nearby include rural homes located off County Road 7 west of the IGCC Power Station Footprint and Buffer Land and off the heavy haul road located to the south. About a dozen residents use the heavy haul road to access their lots located on the northern and western shores of Big Diamond Lake and on the southeast shore of Dunning Lake. Figures 6.3-1 and 6.3-2 are detailed maps showing existing zoning/land use and land cover in the area immediately surrounding the IGCC Power Station Footprint and Buffer Land.

The dominant geographic feature on the IGCC Power Station Footprint is a hill that rises approximately 60 feet east-northeast above the 1425-foot elevation at which the IGCC Power Station's HRSGs will be located. Surrounding topography is generally hilly. Figure 6.3-3 shows the shows ground elevations of the land surrounding the IGCC Power Station Footprint.

6.2 Climatology and Meteorology

Northern Minnesota has a continental-type climate and is subject to frequent outbreaks of continental polar air throughout the year, with occasional Arctic outbreaks during the cold season. Occasional periods of prolonged heat occur during summer, particularly in the southern portion of the State when warm air pushes northward from the Gulf of Mexico and the southwestern United States.

6.3 Background Air Quality

The state of Minnesota uses ambient air monitoring stations to define the air quality of a particular region. Concentrations measured at the monitors are compared to Federal and/or state ambient air quality standards. Monitoring results from the closest monitors to Itasca County are shown in Table 6.3-1. The table includes the average ambient air concentrations over the past three years (2002-2005) for each pollutant and averaging period.

Figure 6.3-1. Land Use/Zoning Within the Immediate Vicinity of the West Range IGCC Power Station

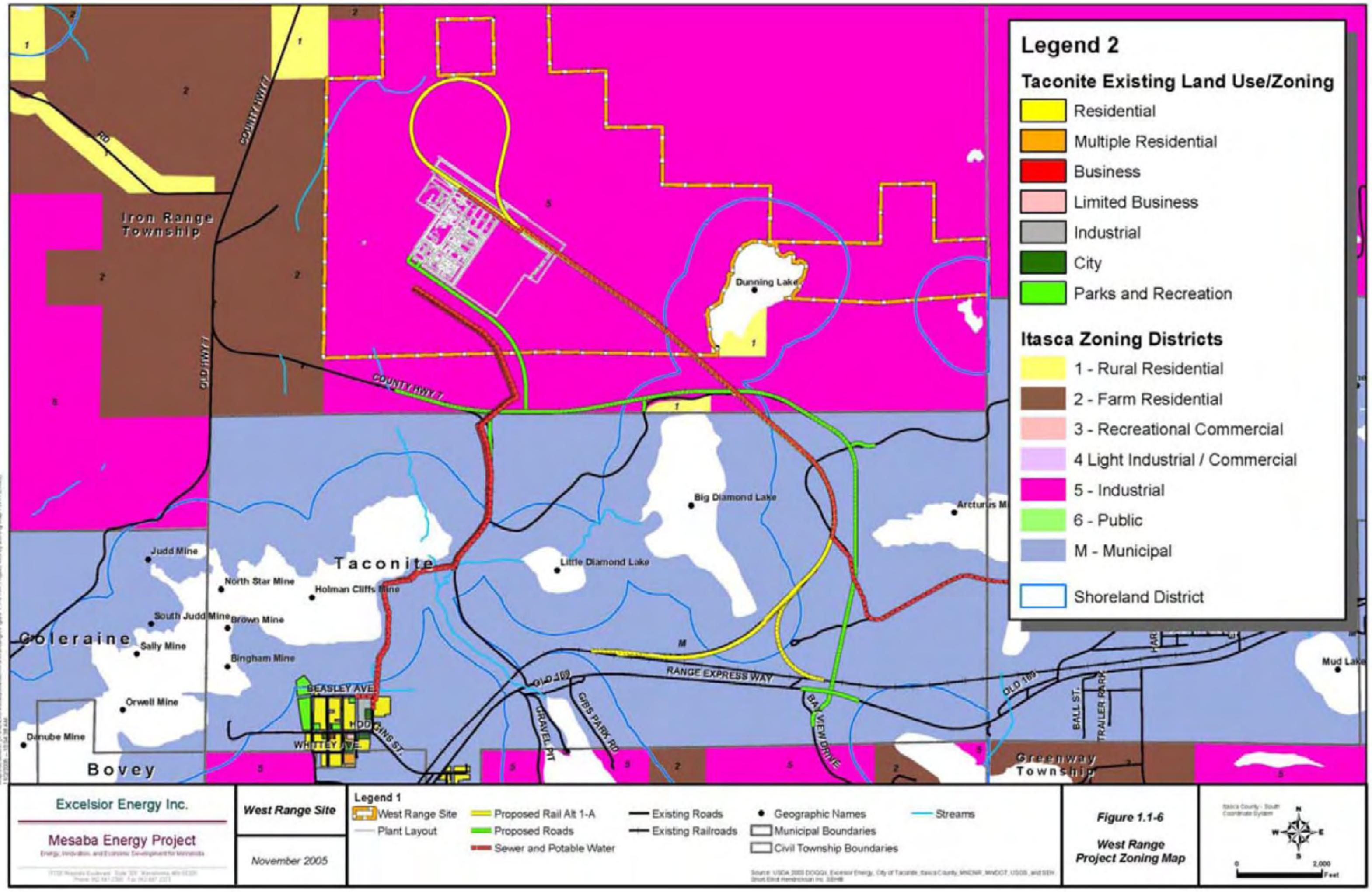


Figure 6.3-2. Land Use and Land Cover Within the Immediate Vicinity of the West Range Site

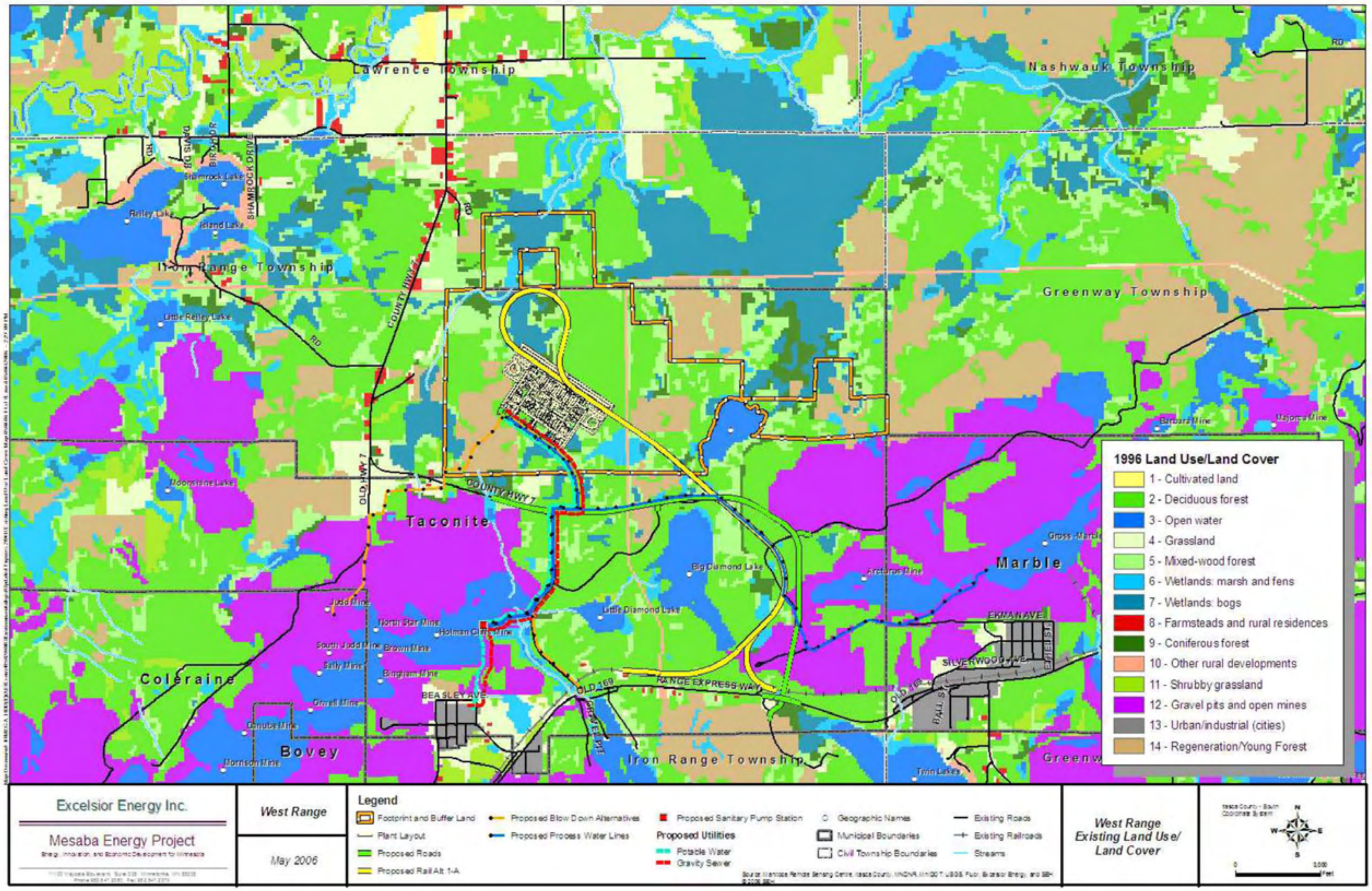


Figure 6.3-3. Topography of the IGCC Power Station Footprint and Buffer Land

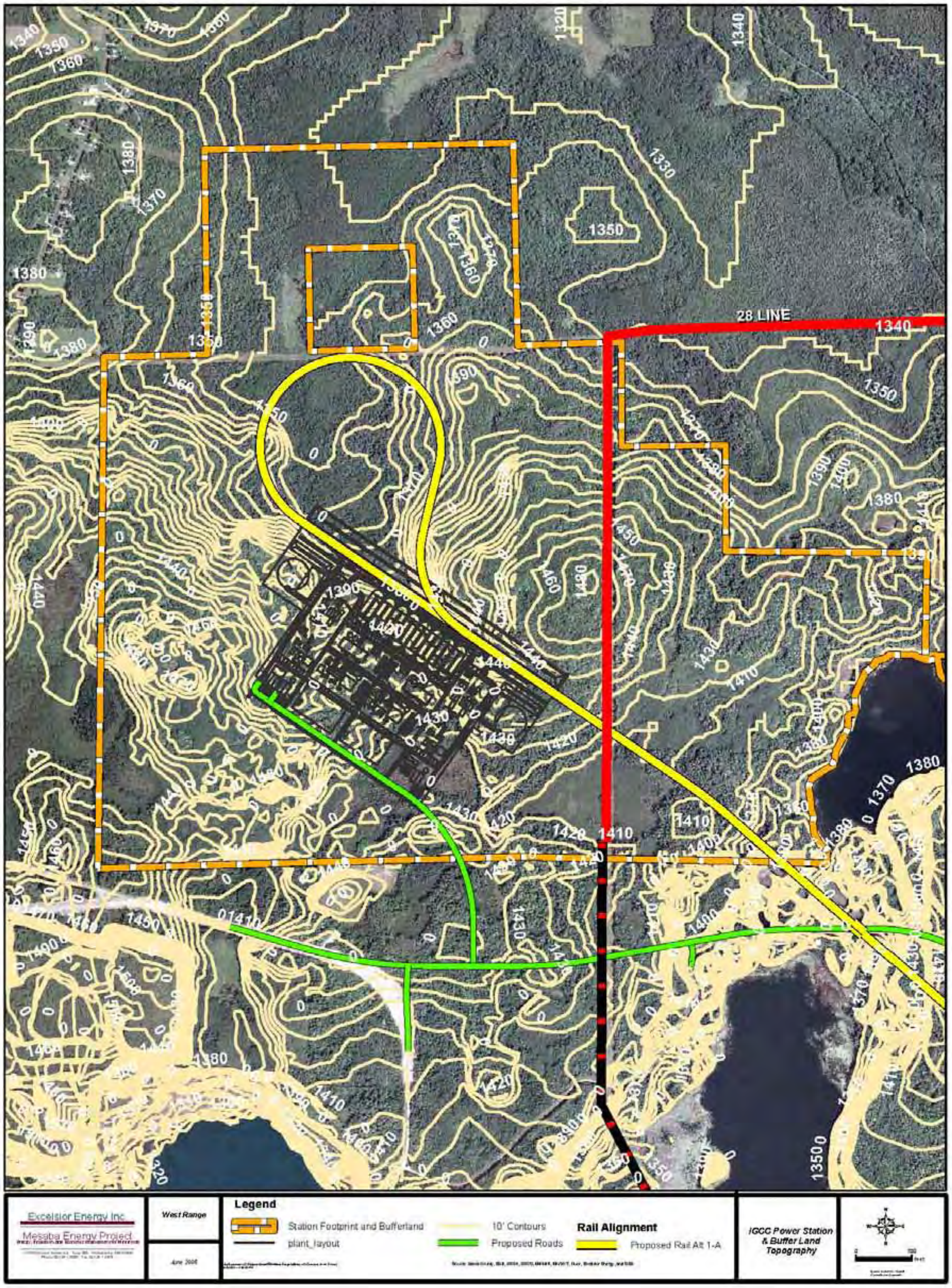


Table 6.3-1
Monitored Background Concentrations

Pollutant	Averaging Period	Monitored Background Concentration	Monitoring Station
Carbon Monoxide	8-Hour	1.6 ppm	314 West Superior Street, Duluth
	1-Hour	3.3 ppm	314 West Superior Street, Duluth
Nitrogen Dioxide	Annual	0.004 ppm	Carlton County
Ozone	8-Hour	0.066 ppm	Voyageurs National Park
Lead	Quarterly	0.01 µg/m3	Virginia City Hall
Total Suspended Particulate (TSP)	Annual	16 µg/m3	Virginia City Hall
	24-Hour	35.7 µg/m3	Virginia City Hall
PM10	Annual	16 µg/m3	Virginia City Hall
	24-Hour	35.7 µg/m3	Virginia City Hall
$PM_{2.5}$	Annual	6.1 µg/m3	Virginia City Hall
	24-Hour	19 µg/m3	Virginia City Hall
Sulfur Dioxide (SO2)	Annual	0.001 ppm	Rosemount, MN
	24-Hour	0.005 ppm	Rosemount, MN
	3-Hour	0.010 ppm	Rosemount, MN
	1-Hour	0.019 ppm	Rosemount, MN

7. AIR QUALITY IMPACT ASSESSMENT

7.1 Modeling Approach

Initial air quality modeling addressed the individual point sources for Mesaba One and Mesaba Two (four CTG stacks, two tank vent boiler (TVB) stacks, two auxiliary boilers, and two flare stacks) as well as all fugitive PM_{10} sources. The modeling was conducted to determine which pollutants will have significant ambient air impacts, and the significant impact area ("SIA") for each pollutant. Applicable significant impact levels are shown in Table 7.1-1.

Modeling was conducted for each pollutant (SO_2, NO_x, CO, PM_{10}), each applicable averaging time, and each emission scenario identified in Section 4.0. The SIA was determined for those pollutants which are shown to have a significant impact in ambient air at any point. The SIA was defined for each pollutant as a circle, centered on the plant site, with a radius equal to the greatest distance to a significant impact for any applicable averaging time or emission scenario.

If any pollutant did not have a significant impact, no further modeling was necessary. For all other pollutants, additional modeling was carried out to evaluate compliance with PSD increments and NAAQS.

PSD increment analyses were implemented for SO_2, NO_2, and PM10. Allowable increments are listed in Table 7.1-1. Source input for increment modeling included all point sources associated with Mesaba One and Mesaba Two and all regional increment-consuming sources included in the emissions inventory provided by the MPCA.

NAAQS analyses were conducted for SO_2, NO_2, PM_{10}, and CO. Applicable NAAQS are given in Table 7.1-1. In addition to those sources included in the increment analysis, additional nearby sources (provided by MPCA) were added to the source inventory. Regional source impacts were included (for worst-case modeled impact times and receptors) by modeling the "FARDATA" emission inventory appropriate to the vicinity of the West Range Site as provided by MPCA modeling staff. For comparison to the NAAQS, a background concentration representing natural or pristine background plus one significant impact level ("SIL") was added to all model-predicted concentrations.

In addition to the modeling analyses described above, model results were applied to address other PSD requirements: the potential need for pre-construction monitoring and additional impact analyses relating to growth, soils and vegetation, visibility impairment, and deposition.

Table 7.1-1
Applicable Air Quality Standards, Increments and SILs for Mesaba One and Mesaba Two*

Pollutant	Averaging Time	NAAQS ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
SO_2	One-Hour	1300	512	25
	Three-Hour	915	512	25
	24-Hour	365	91	5
	Annual	60	20	1
NO_2	Annual	100	25	1
PM10	24-Hour	150	30	5
	Annual	50	17	1
CO	One-Hour	40,000	NA	2000
	Eight-Hour	10,000	NA	500

* There are also criteria pollutant NAAQS for ozone (0_3) and Lead. 0_3 modeling is not normally appropriate for PSD application analyses. Lead emissions will be less than the PSD Significant Emission Rate.

7.2 Modeled Emission Rates

Table 7.2-1 shows estimated annual emissions of criteria pollutants for each of the two phases associated with Mesaba One and Mesaba Two. Based upon these data, Mesaba One and Mesaba Two will be a major stationary source to be located in a PSD area, and will therefore be subject to PSD new source review permitting requirements for each of the pollutants shown. Air quality modeling demonstrations of compliance with PSD increments is also required for SO_2, NO_2, and PM_{10}, and a demonstration of compliance with Minnesota/National Ambient Air Quality Standards (NAAQS) is required for SO_2, NO_2, PM_{10}, and CO.

Tables 7.2-2, 7.2-3, and 7.2-4 present maximum expected point source criteria pollutant emission rates from each phase of Mesaba One and Mesaba Two for different averaging times and operating scenarios. All emission rates are taken directly from the specifications presented in Section 4. The emission rates shown, along with the stack parameters in Table 7.2-5, were used as model input for the air modeling analyses.

The data presented in Table 7.2-2 represent emissions during normal operation of Mesaba One and Mesaba Two. These emission rates were modeled as the "base case" to define the expected air quality impacts of the power station.

Emission rates and stack gas conditions for short-term averaging times can be different from those shown in Table 7.2-2 during non-steady-state operating scenarios such as startup and flaring of syngas. To address these short-term conditions, air modeling was also carried out for applicable averaging times (24 hours and less) using the emission rates given in Tables 7.2-3 and 7.2-4. The emission rates represent worst-case maximum emissions for each scenario. The applicable stack parameters are also shown in Table 7.2-5.

Other sources at the IGCC Power Station consist of two emergency fire pumps and two emergency diesel generators per phase. Since these sources will operate for only short time periods when the primary emission sources are not in operation, they were not included in the air modeling analyses. Hours of operation of such facilities will likely be limited by permit conditions. The emissions from periodic testing of these emergency resources are negligible.

Fugitive emissions of PM_{10} will result from the storage and handling of coal and other materials. Annual emissions from these fugitive sources are shown in Table 7.2-2. All fugitive PM_{10} sources were included in the air modeling, as described subsequently in this Application.

Table 7.2-1
Worst-Case Annual Emissions (Tons/year) From Mesaba One and Mesaba Two
(Each Phase)

Source	SO_2	NO_x	CO	VOC	PM10
Combustion Turbines (total for two)	666	1386	964	88	220
Tank Vent Boiler	15.8	26.4	7.9	0.4	0.9
Auxiliary Boiler	0.4	5.1	10.5	0.6	0.7
Flare	12.3	13.4	285.9	1.3	1.7
Cooling Towers					19.7
Coal Handling					2.0
Slag Handling					1.0
Coal Slurry Facility					0.2
Total	694.5	1430.9	1268.3	90.3	246.2

Table 7.2-2
Modeling Emission Rates for Normal Operation of Mesaba One and Mesaba Two[1] – Each Phase

Source/Averaging Time	SO_2		CO		PM10[2]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Combustion Turbines (each of two)								
One-Hour	183	23.06	95	11.97				
Three-Hour	152	19.15						
Eight-Hour			95	11.97				
24-Hour	114	14.36			25	3.15		
Annual	76	9.58			25	3.15	158	19.91
Tank Vent Boiler								
One-Hour	8.4	1.06	5.9	0.74				
Three-Hour	7.5	0.94						
Eight-Hour			5.9	0.74				
24-Hour	6.4	0.81			0.7	0.09		
Annual	3.6	0.45			0.2	0.03	6.0	0.76
Auxiliary Boiler								
One-Hour	0.37	0.05	9.6	1.21				
Three-Hour	0.37	0.05						
Eight-Hour			9.6	1.21				
24-Hour	0.37	0.05			0.65	0.08		
Annual	0.09	0.01			0.16	0.02	1.16	0.15

Table 7.2-2
Modeling Emission Rates for Normal Operation for Mesaba One and Mesaba Two[(1)] – Each Phase Continued

Source/Averaging Time	SO_2		CO		PM10[(2)]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Flare								
One-Hour	0.01	0.001	1.10	0.14				
Three-Hour	0.01	0.001						
Eight-Hour			1.10	0.14				
24-Hour	0.01	0.001			0.02	0.002		
Annual	2.8	0.35			0.38	0.05	3.1	0.39

(1)Short-term emissions represent normal plant operation on syngas fuel; annual emissions are worst-case annual operation including flaring, gasifier outages, etc.
(2)PM_{10} emissions include filterable and condensable portions.

Table 7.2-3
Modeling Emission Rates for Worst-Case Flaring Scenario for Mesaba One and Mesaba Two-Each Phase

Source/Averaging Time	SO_2		CO		PM_{10}[1]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	G/s	lb/hr	g/s
Combustion Turbines (each of two)								
One-Hour								
Three-Hour								
Eight-Hour								
24-Hour								
Tank Vent Boiler								
One-Hour								
Three-Hour								
Eight-Hour								
24-Hour								
Auxiliary Boiler								
Flare								
One-Hour	1040	131.04	5680	715.67				
Three-Hour	734	92.48						
Eight-Hour			5345	637.46				
24-Hour	183	23.06			14.1	1.78		

[1] PM_{10} emissions include filterable and condensable portions

Table 7.2-4
Modeling Emission Rates for Worst-Case Start-up Operating Scenario – One Phase

Source/Averaging Time	SO_2		CO		PM10[1]		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Combustion Turbines								
(each of two)								
One-Hour	183	23.06	2740	345.23				
Three-Hour	152	19.15						
Eight-Hour			541	68.21				
24-Hour	114	14.36			25	3.15		
Tank Vent Boiler								
One-Hour	8.4	1.06	5.9	0.74				
Three-Hour	7.5	0.94						
Eight-Hour			5.9	0.74				
24-Hour	6.4	0.81			0.7	0.09		
Auxiliary Boiler	0.37	0.05	9.6	1.21	0.65	0.08		
Flare								
One-Hour	0.11	0.01	22	2.77				
Three-Hour	0.11	0.01						
Eight-Hour			22	2.77				
24-Hour	0.11	0.01			0.32	0.04		

(1) PM_{10} emissions include filterable and condensable portions
All flare emissions and Combustion Turbine CO emissions represent start-up operation. These rates exceed Normal Operation values. All other emission rates are worst-case Normal Operation values, which are higher than during startup.

Table 7.2-5
Modeling Stack Parameters

Source/Scenario Averaging Time	Stack Height. (m)	Stack Diameter (m)	Gas Temperature (K)	Velocity (m/s)
Combustion Turbines (each)				
Normal Operation	45.72	6.10	394.3	20.08
Startup	45.72	6.10	366.5	11.64
Tank Vent Boiler				
Short-term	64.01	1.83	579.8	8.46
Annual	64.01	1.83	579.8	1.95
Start-up	64.01	1.83	579.8	5.21
Auxiliary Boiler	12.19	1.52	422.1	9.70
Flare(1)				
Normal Operation	56.39	0.25	1273.0	20.0
Start-up	56.39	1.11	1273.0	20.0
Flaring: One-Hour	56.39	10.72	1273.0	20.0
Three-Hour	56.39	10.40	1273.0	20.0
Eight-Hour	56.39	10.40	1273.0	20.0
24-Hour	56.39	7.36	1273.0	20.0
Annual	56.39	0.25	1273.0	20.0

(1) Flare parameters determined by SCREEN 3 methodology based on total heat release

7.3 Modeling Methodology

7.3.1 Model and Options

The AERMOD air quality model was used with the PRIME building downwash algorithm (Version 04300) for all IGCC Power Station Class II modeling. As MPCA prefers the AERMOD modeling system for this application, and since EPA has now included AERMOD as an approved Guideline model, AERMOD is deemed to be the preferred choice for IGCC Power Station permitting.

AERMOD was used with all regulatory options, and included:

- stack-tip downwash
- elevated terrain effects
- calms processing
- missing data processing
- "upper bound" values for supersquat buildings
- no exponential decay

No wet or dry depletion/deposition was included. The model was set to RURAL dispersion as the terrain/land use within three kilometers of the site is almost totally rural.

7.3.2 Meteorological Data

The MPCA has processed meteorological data suitable for input to AERMOD for many locations in Minnesota. At the Applicant's request, Mr. Dennis Becker provided on July 5, 2005 an AERMET data file (HI475935.ZIP) that was processed specifically for the area including the IGCC Power Station Footprint. The meteorological data are based upon Hibbing, Minnesota hourly surface weather observations for the years 1972 through 1976. These meteorological data were used for all IGCC Power Station modeling with AERMOD.

7.3.3 Building Downwash

Building wake effects on dispersion are accounted for using the PRIME downwash algorithm in AERMOD. Direction-specific building dimensions and related parameters are generated with EPA's BPIP PRIME program.

7.3.4 Receptor Grid

The receptor grid for the IGCC Power Station consists of seven nested Cartesian grids covering a total 441 km^2 area (21 x 21 km) surrounding the plant site. The grid is shown in Figure 7.3-1.

Receptors are located along the IGCC Power Station fence line with a spacing of 10 meters. The inner Cartesian grid, with a spacing of 25 m, covers an approximate 2.5 km^2 area surrounding the plant site. Successive grids at greater distances from the fence line have gradually increasing spacing. The dimensions and spacing of all grids are provided in Table 7.3-1.

Figure 7.3-1. Modeling Receptor Grid and Terrain Elevations (m)

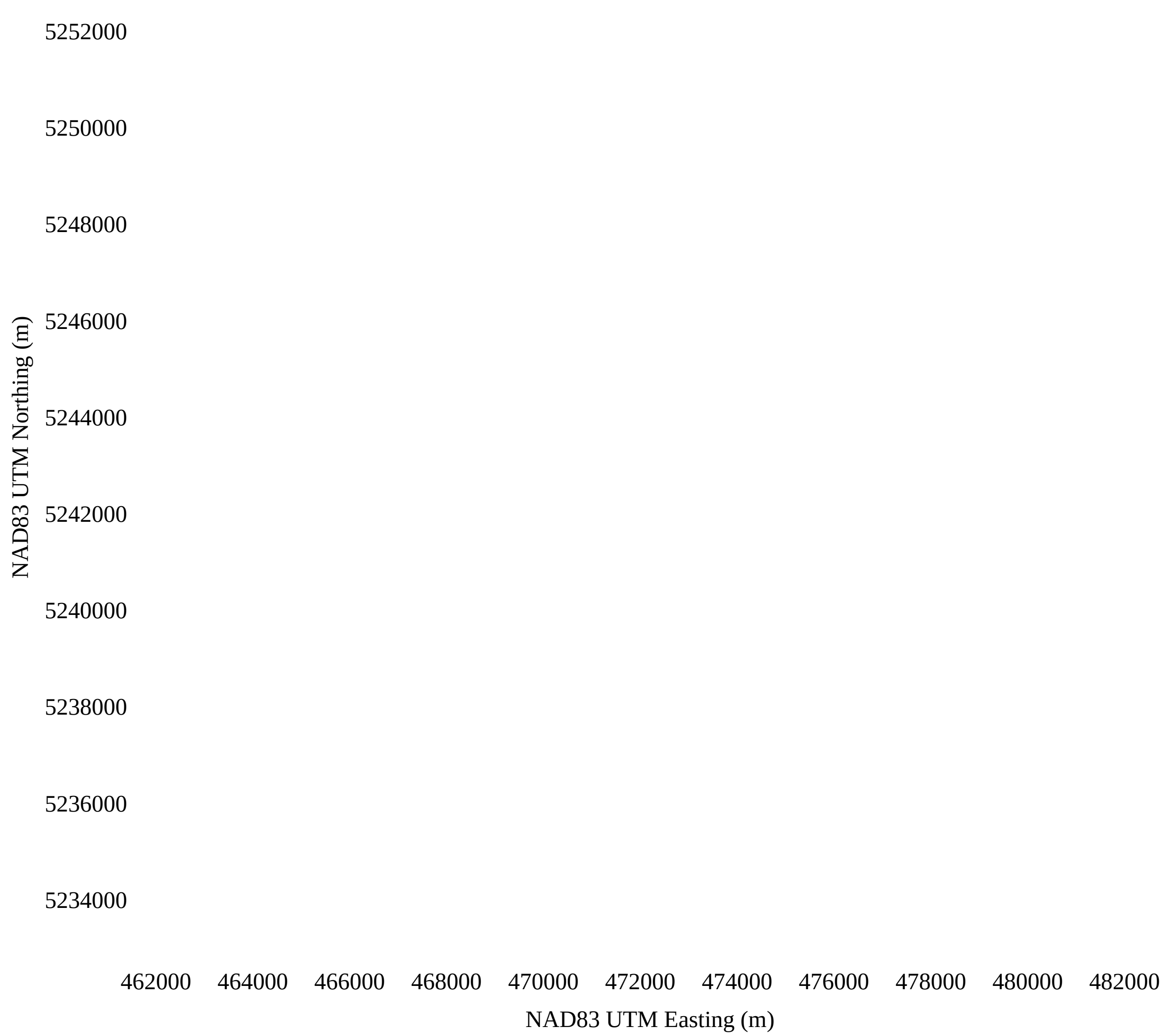


Figure 7.3-1
Figure 34
Modeling Receptor Grid and
Terrain Elevations (m)

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Table 7.3-1
IGCC Power Station Receptor Grids

Grid Level	Level Description	Spacing
1st	IGCC Power Station fence line	10-meter
2nd	2.4 km area around site	25-meter
3rd	0.25-km wide border	50-meter
4th	0.5-km wide border	100-meter
5th	1.0-km border	200-meter
6th	3.0-km border	500-meter
7th	5.0-km wide border	1000-meter

Terrain elevations for all receptors were determined from USGS 7.5 minute DEM data and were processed with AERMAP.

7.3.5 Regional Source Input

A request was submitted to the MPCA for regional source inventories applicable to modeling for the West Range IGCC Power Station. Data were provided by Chris Nelson (8/17/05) that included increment consuming sources, and "nearby" major sources of air pollutant emissions. Increment consuming (and expanding) source emissions were provided for the following:

- Blandin Paper Company/Rapids Energy Center
- Potlatch – Grand Rapids
- Minnesota Power – Clay Boswell

Other nearby source data were provided for:

- Keewatin Taconite
- Minnesota Power – Clay Boswell

The appropriate input data for the above sources were included, along with IGCC Power Station data, for all increment and NAAQS modeling analyses. All increment modeling employed the "two-entry" approach using negative emission rates for emissions on the minor source baseline date and positive emission rates for post-baseline data conditions. Of note, the major emission reduction proposals recently announced by Minnesota Power were not included in the Applicant's modeling, thereby introducing a further degree of conservatism into the resulting emission profiles.

7.4 Background Concentrations

To account for impacts of distant and regional sources, the First-Approximation Run (FAR) data approach developed by D. Becker at MPCA was applied. With this approach, a distant/regional modeling inventory (FARDATA) was included in EVENT model runs for highest impact cases. The FAR data provide an approximation of the date/time specific impacts of all regional sources, which were added to the impacts from the IGCC Power Station and nearby sources. An inventory developed specifically for use within the vicinity of the West Range IGCC Power Station has been provided by the MPCA (FARDATA, C. Nelson, 8/17/05).

For comparison to PSD increments, one significant impact level (SIL) is added to final model-predicted concentrations, in accordance with MPCA guidance. For the NAAQS analyses, one SIL plus a "natural background" concentration was added to total model-predicted concentrations. The following natural background concentrations were utilized and are proposed:

- SO_2 10 µg/m^3 short-term averaging periods
  2 µg/m^3 annual average
- NO_2 5 µg/m^3 annual average
- PM_{10} 20 µg/m^3 24-hour average
  10 µg/m^3 annual average

7.5 Significant Impact Analysis

The Mesaba facility (two phases) was modeled alone to determine the highest predicted concentration for each pollutant, each averaging time, and all operating scenarios. The results of this modeling are summarized in Table 7.5-1

The modeling for each scenario in Table 7.5-1 represents a worst-case emissions scenario. For normal operation, the emissions are included from both phases at 100% capacity for 8760 hours per year. The flaring scenario represents both flares at maximum SO_2 emissions for the applicable averaging times, with no emissions from other plant sources. Only SO_2 and CO impacts of the flares are relevant, since PM_{10} and NO_x emissions for the total facility are far below normal operation values. The startup scenario assumes all combustion turbines in startup mode, with other sources at maximum emission rates for any condition. Startup modeling was limited to CO, since facility-wide emissions of all other pollutants will be less than in normal operation.

Table 7.5-1
Highest Model-Predicted Concentrations For Mesaba One and Mesaba Two (Both Phases) (µg/m^3)

Pollutant and Averaging Time	Normal Operation	Flaring	Startup	SIL
SO_2				
one-hour	130.2	75.8	N/A	25.0
three-hour	77.6	22.8	N/A	25.0
24-hour	31.2	5.4	N/A	5.0
Annual	1.29	N/A	N/A	1.0
PM10				
24-hour	27.9	N/A	N/A	5.0
Annual	1.68	N/A	N/A	1.0
CO				
one-hour	172.2	414.1	3167.5	2000
eight-hour	59.8	122.7	379.0	500
NO_x				

Inspection and review of the data presented in Table 7.5-1 produces the following conclusions:

(1) Impacts are above the applicable SIL for all pollutants and all averaging times except for eight hours for CO.
(2) Impacts are greatest under normal operating conditions, except for CO; highest CO impacts will occur during startup.

Because the highest predicted impacts were significant, increment and NAAQS compliance modeling was necessary for SO_2, PM10, and NO_x. For CO there are no applicable PSD increments, and NAAQS compliance need only be demonstrated for the one-hour ambient standard. The normal operation scenario was addressed in all increment and NAAQS analyses for SO_2, PM10, and NO_x since they represent the highest concentrations. The startup scenario was addressed only for the CO one-hour NAAQS demonstration. No further modeling was conducted for the flaring scenario since it produces lower concentrations than created under other scenarios.

Figures 7.5.1 though 7.5-6 show outlines of the model-predicted areas that can experience significant impacts for each pollutant and averaging time. Based upon the contours shown, the maximum radius of the Significant Impact Area (SIA) for each pollutant is:

SO_2	4.4 km
PM10	1.6 km
NOx	3.0 km
CO	0.9 km

All highest predicted concentrations were found to occur within approximately one kilometer of the IGCC Power Station Footprint. Thus, impacts of Mesaba and Two will be limited to a small area in close proximity to the Site. Specific locations, dates, and times of highest predicted impacts are included in Appendix D of this Application.

Figure 7.5-1. SO_2 3-Hour Significant Impact Area (µg/m^3)

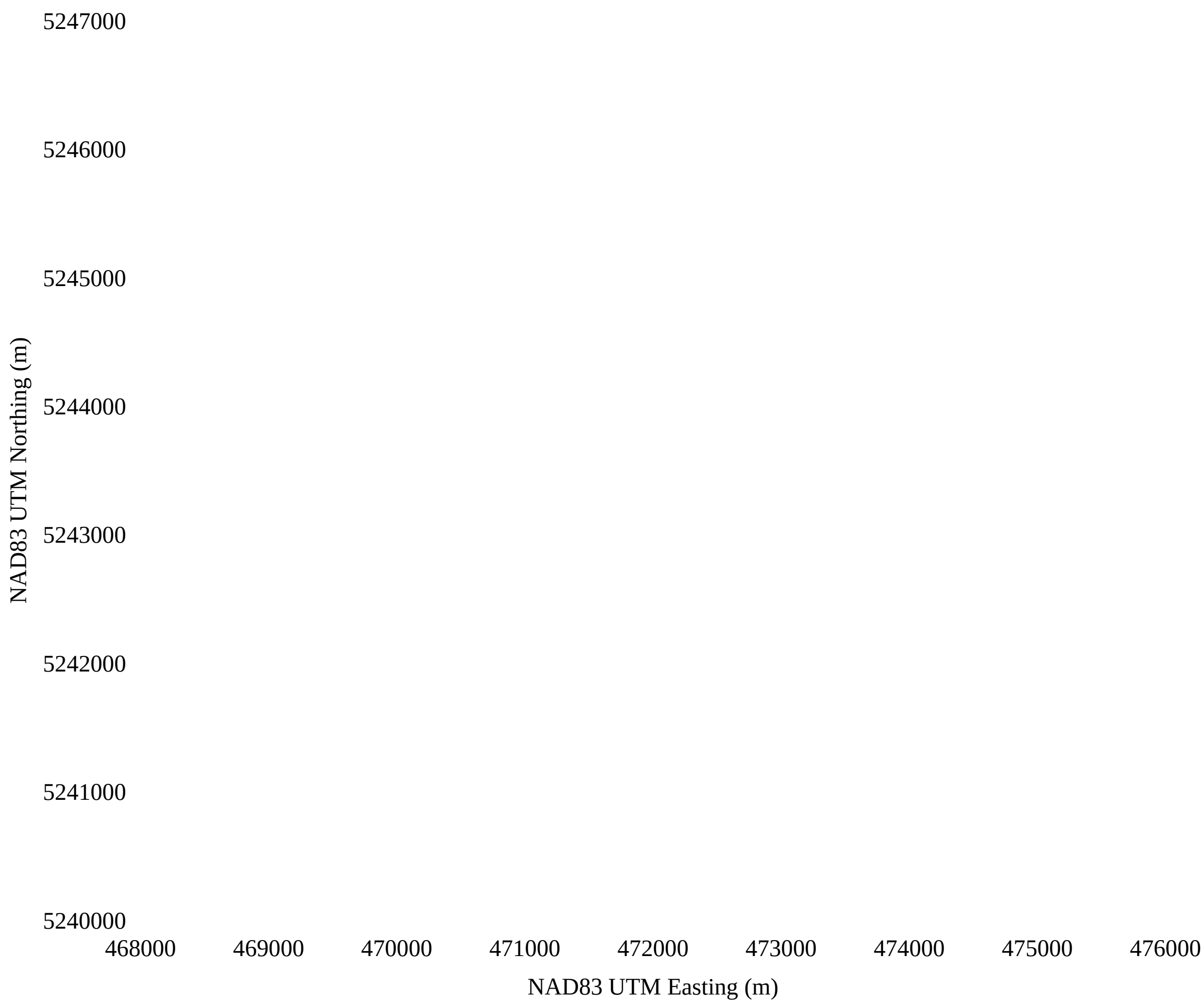

Figure 7.5-1
Figure 35
SO_2 3-Hour Significant Impact Area (µg/m^3)
For Mesaba Phase I and II – Normal Operations
Data Years 1972-1976

Figure 7.5-2. SO_2 24-Hour Highest Second High Impacts ($\mu g/m^3$)

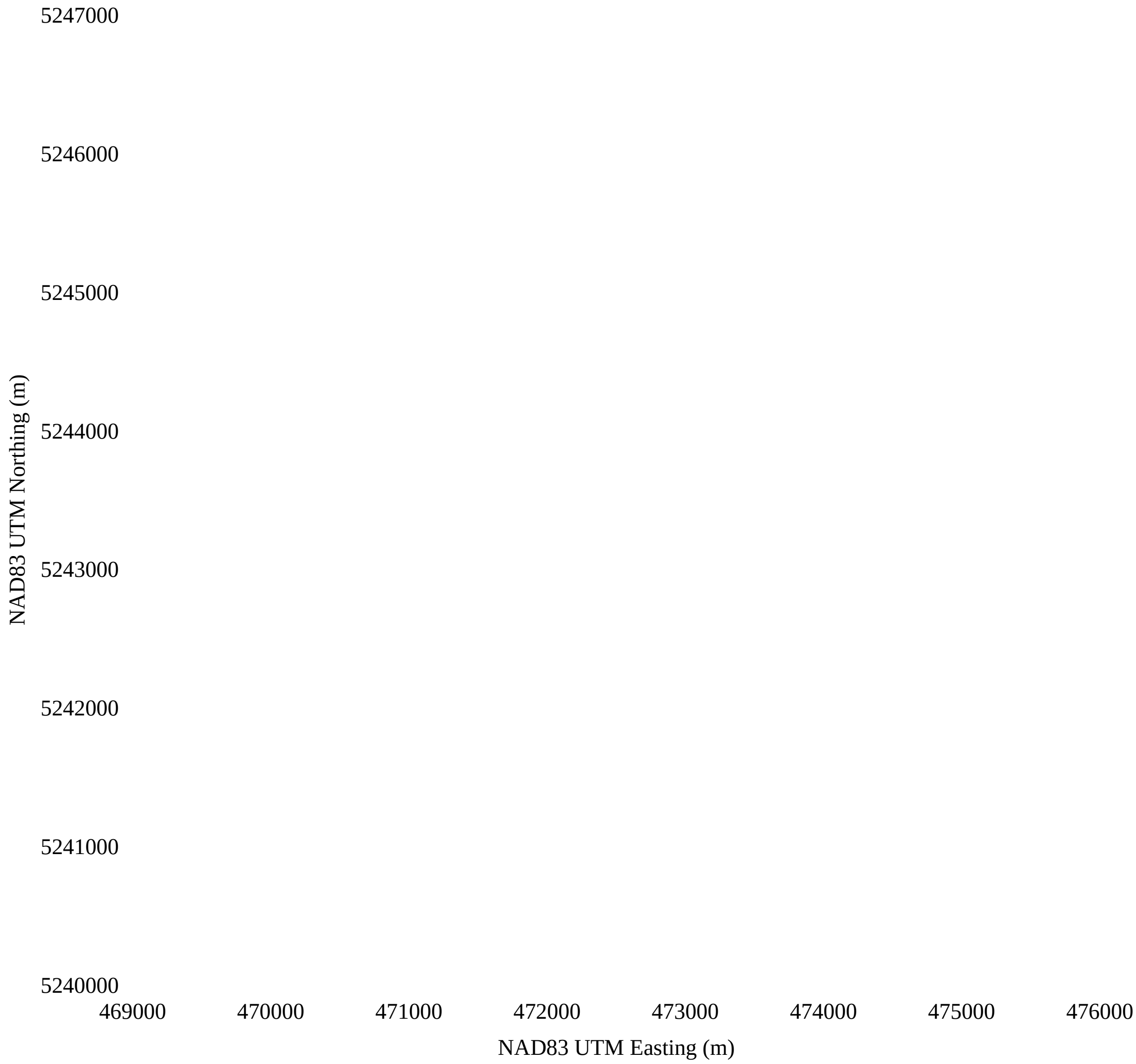

Figure 7.5-2
Figure 36
SO_2 24-Hour Highest Second High Impacts ($\mu g/m^3$)
For Mesaba Project Phase I and II and Nearby Sources
Data Year 1975

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Figure 7.5-3. SO_2 Annual Significant Impact Area (µg/m^3)

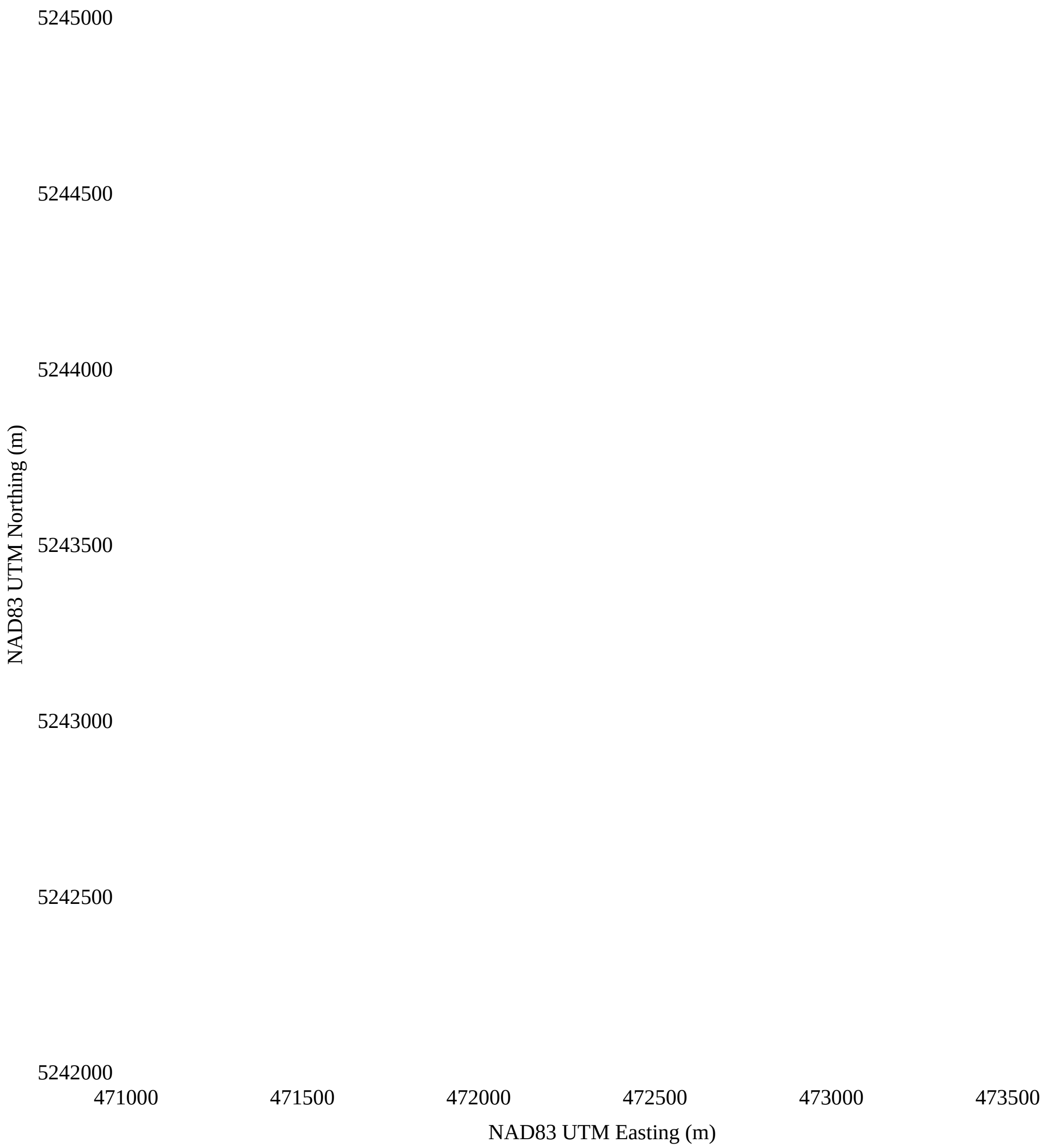

Figure 7.5-3
Figure 37
SO_2 Annual Significant Impact Area (µg/m^3)
For Mesaba Phase I and II – Normal Operations
Data Years 1972-1976

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Figure 7.5-4. PM$_{10}$ 24-Hour Significant Impact Area (µg/m^3)

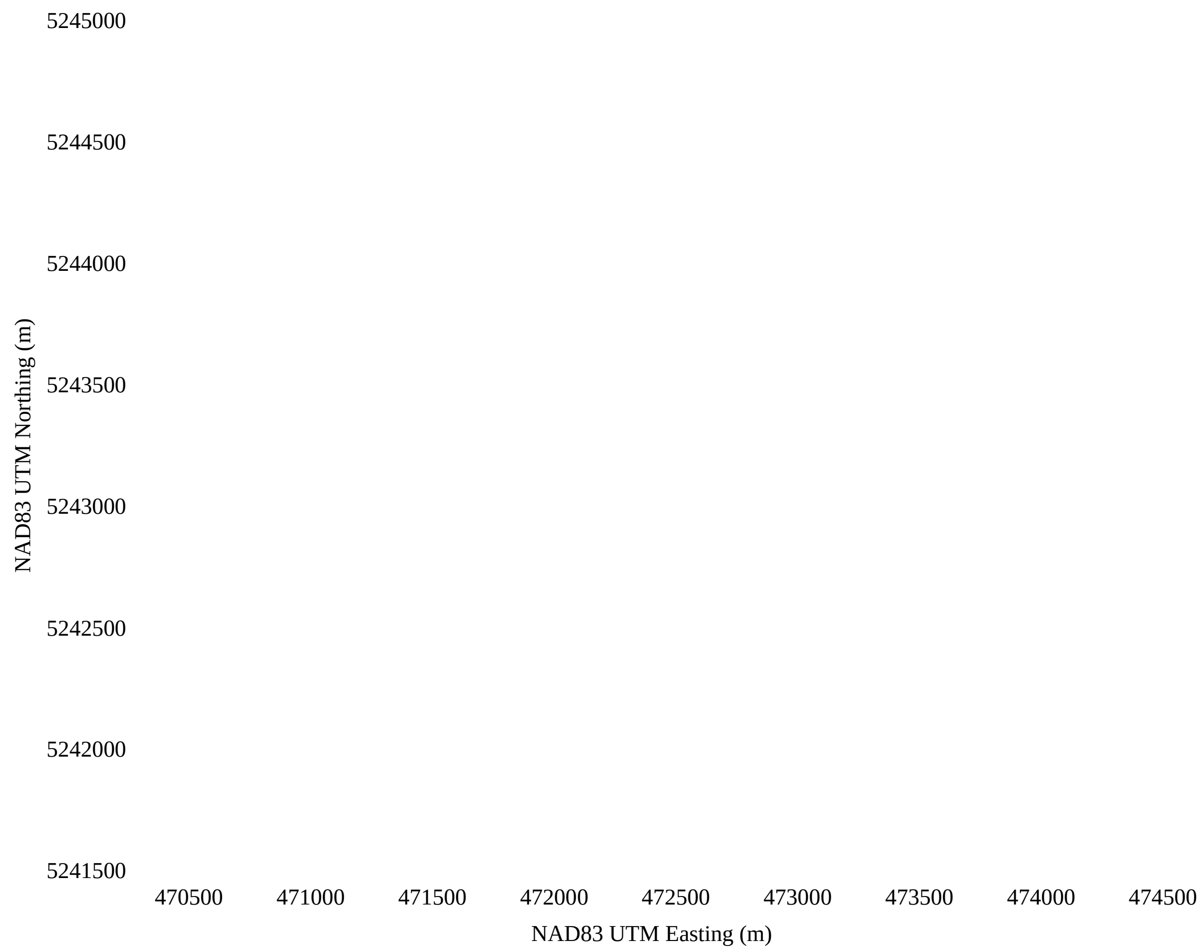

Figure 7.34
PM$_{10}$ 24-Hour Significant Impact Area (µg/m^3)
For Mesaba Phase I and II – Normal Operations
Data Years 1972-1976

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Figure 7.5-5. PM_{10} Annual Significant Impact Area ($\mu g/m^3$) Mesaba One and Mesaba Two – Normal Operations

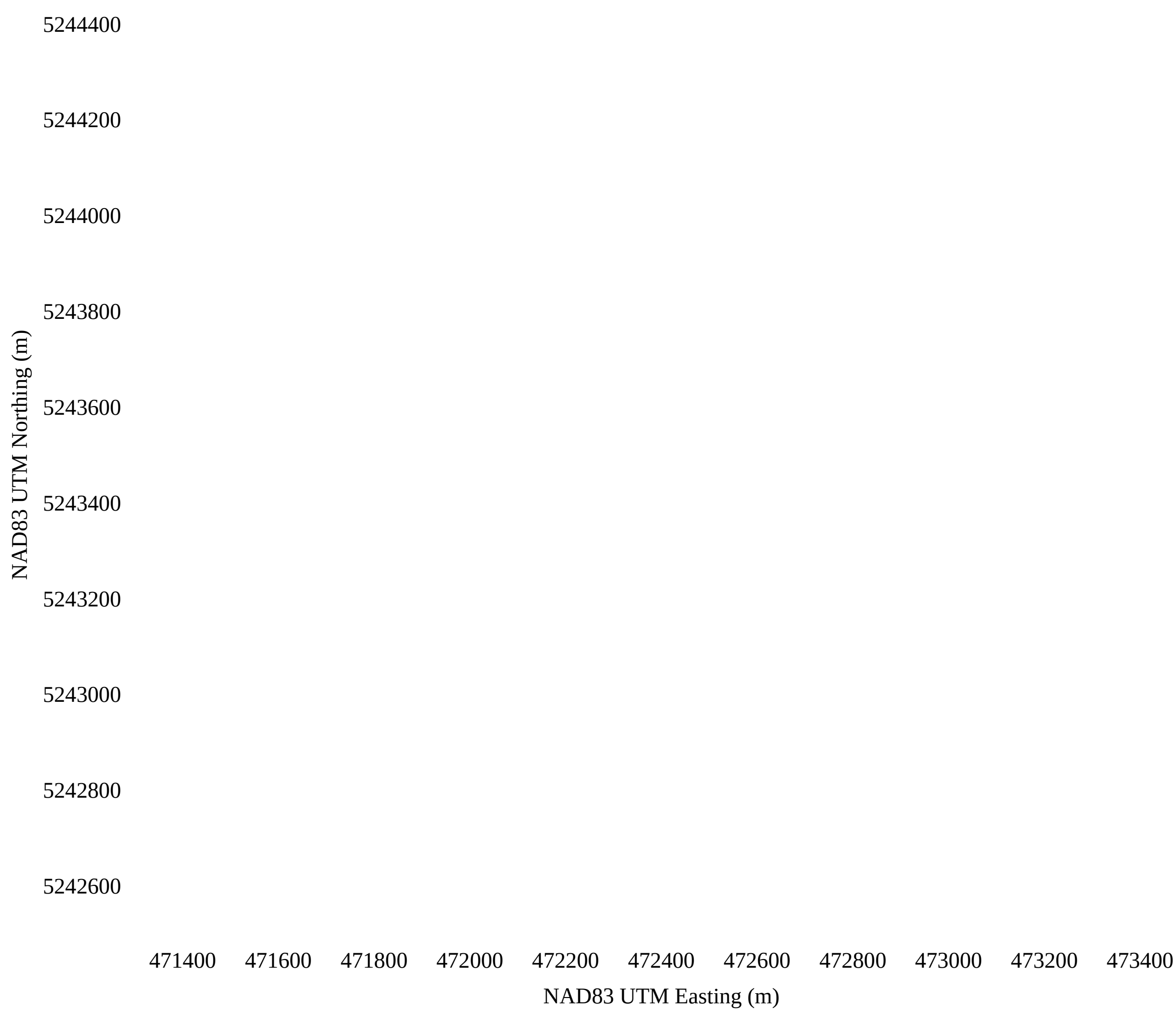

Figure 7.5-5
Figure 39
PM_{10} Annual Significant Impact Area ($\mu g/m^3$)
For Mesaba Phase I and II – Normal Operations
Data Years 1972-1976

Figure 7.5-6. CO 1-Hour Significant Impact Area (µg/m^3) Mesaba One and Mesaba Two Startup

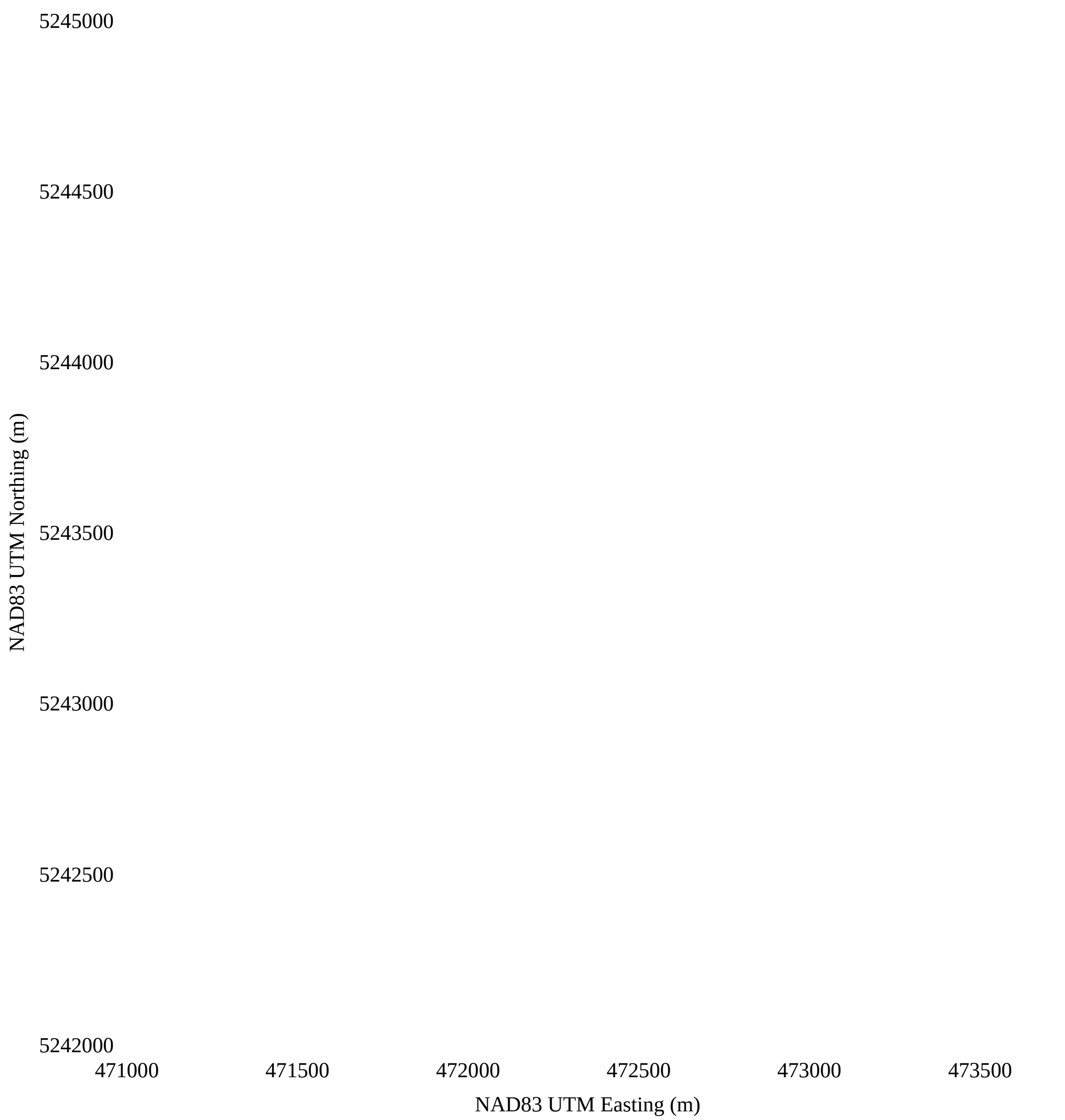

Figure 7.5-6
Figure 40
CO 1-Hour Significant Impact Area (µg/m^3)
For Mesaba Phase I and II – Startup
Data Years 1972-1976

Figure 7.5-7. NO_X Annual Significant Impact Area ($\mu g/m^3$) Mesaba One and Mesaba Two Normal Operations

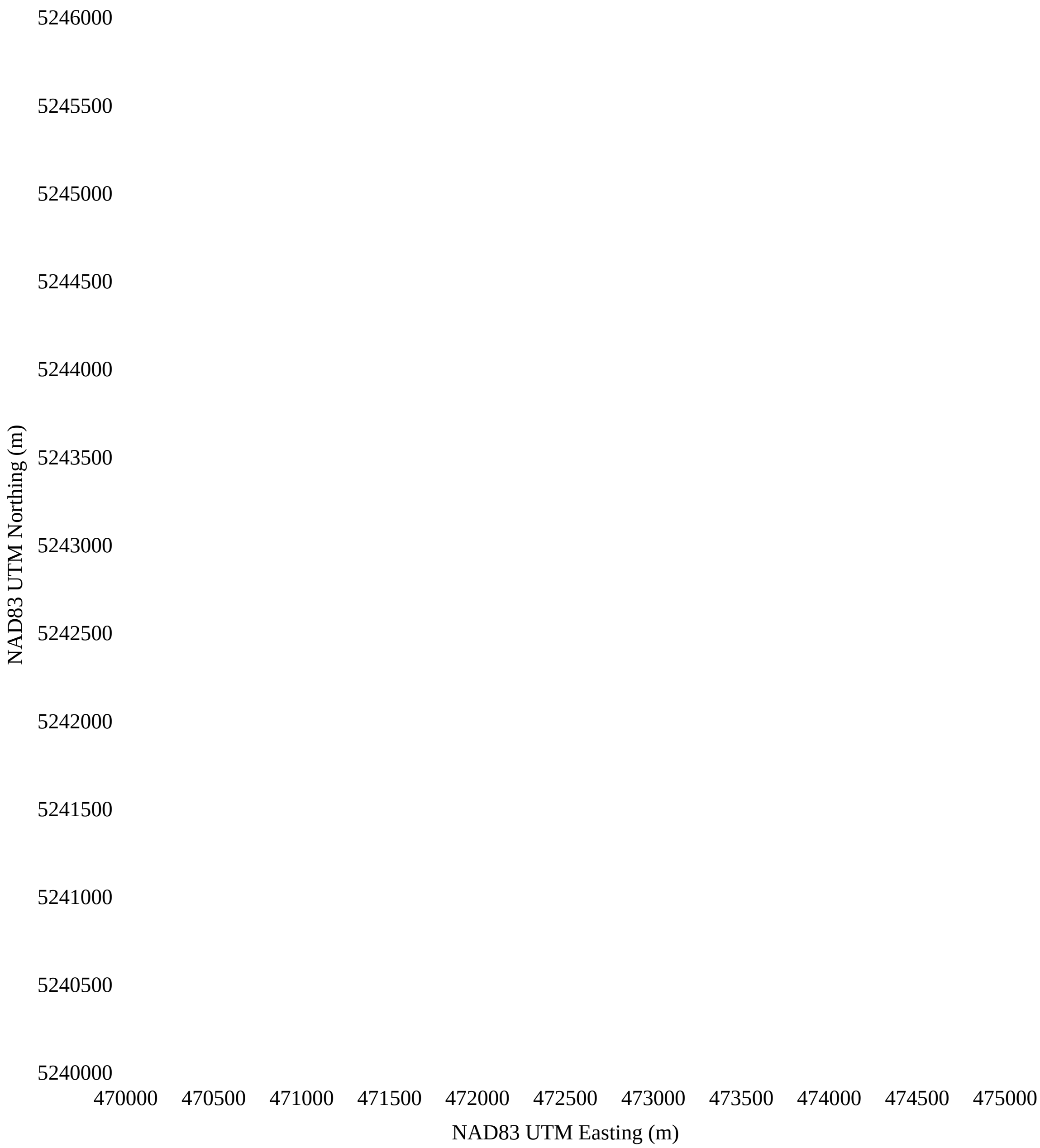

Figure 7.5-7
Figure 41
NO_X Annual Significant Impact Area ($\mu g/m^3$)
For Mesaba Phase I and II – Normal Operations
Data Years 1972-1976

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7.6 PSD Increment Analysis

Increment analyses were completed for SO_2, PM10, and NO_x. The modeling included all Mesaba One and Mesaba Two sources at maximum emission rates in normal capacity operation, plus all regional increment consuming (and expanding) emissions listed in inventories provided by the MPCA. Increment consuming emissions were included in the input file as positive numbers and increment-expanding emissions (decreases since the baseline date) were included as negative numbers. Total modeled emissions of regional increment sources are listed in Table 7.6-1. Importantly, the emissions listed in Table 7.6-1 for the Clay Boswell plant relate to the permitted short-term limits for Boiler No. 4. A review of historical data over the past 2.5 years revealed that the actual peak short-term SO_2 emissions for that boiler averaged approximately 1,600 pounds per hour. Nonetheless, the permitted emission rate of 6,131 pounds per hour for Clay Boswell Unit No. 4 was used for the near-field increment analysis to provide a conservative estimate of total increment consumption.

Table 7.6-1
Regional Source Increment Consuming Emissions for Mesaba One and Mesaba Two PSD Increment Modeling

Source	SO_2		PM10		NO_x	
	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
Blandin Paper Company	-178.68	-22.513	-0.13	-0.016	-116.91	-14.730
	+595.66	+75.052	+53.84	+6.784	+117.72	+14.832
Minnesota Power – Clay Boswell	6130.89	772.48	510.90	64.373		
Potlatch – Grand Rapids			63.40	7.988	95.67	12.054

The results of the increment analyses are shown in Table 7.6-2, along with a comparison to the allowable Class II PSD increments. The data in Table 7.6-2 demonstrate that the Mesaba One and Mesaba Two, in combination with all other regional PSD sources, will comply with all increment limits. All highest increment impacts leave a margin of at least one SIL for future growth. Maximum increment impacts of Mesaba One and Mesaba Two and regional sources are generally in the same location and are of nearly the same magnitude as those of Mesaba One and Mesaba Two alone. Thus, there is very little impact by other regional increment-consuming sources in the area of Mesaba One and Mesaba Two impacts. Significant increment impacts of Mesaba One and Mesaba Two are limited to the immediate vicinity of the IGCC Power Station Footprint (see Figures 7.3-1 through 7.5-6), and are well within allowable limits.

Table 7.6-2
Results of Mesaba Class II PSD Increment Analysis (µg/m3)

Pollutant/Averaging Time	Highest* Concentration	PSD Increment
SO_2: One-hour	122.4	512
Three-hour	73.4	512
24-hour	21.1	91
Annual	1.40	20
PM10: 24-hour	23.5	30
Annual	1.72	17
NO_2: annual	2.62	25

*For short-term periods, the highest second-high concentration from five years of meteorological data is shown. For annual average, the highest concentration for any of the five years is listed.

7.7 NAAQS Analysis

The NAAQS modeling demonstration consisted of calculating the maximum impact of Mesaba One and Mesaba Two sources and all other regional sources, and comparing the highest total impacts, plus background concentrations, to the applicable Minnesota Ambient Air Quality Standards and NAAQS. For Mesaba One and Mesaba Two, maximum emission rates in normal operation were modeled for all sources and pollutants, except in the case of CO for which the startup scenario has maximum impacts.

For inclusion of other regional sources, a two step procedure was utilized following the recommendations of MPCA modeling staff. In the first step, Mesaba One and Mesaba Two were modeled along with nearby sources for which emission parameters were provided by the MPCA. The location and time of high and highest second-high concentrations were defined by these model results. These specific high impact events were then remodeled, through use of the AERMOD EVENT option and included a much larger inventory of all regional sources. The full regional inventory, referred to as First Approximation Run ("FAR") data, was provided by the MPCA. FAR data files were generated specifically for the IGCC Power Station and separate files were provided for each pollutant and averaging time.

The application of the FAR data provides an approximation of the combined impacts of all sources for the specific times and receptors that were modeled. If predicted impacts threaten ambient standards, or if there is indication of significant interaction between multiple sources, then more refined multiple source modeling could be necessary. However, as shown in the following, the highest predicted impacts in the Mesaba analysis are far below applicable standards, and there are very low impacts of regional sources within the Mesaba SIA. Therefore, the FAR DATA methodology in this case provides assurance of compliance with all NAAQS limits.

Table 7.7-1 summarizes results of the NAAQS model analysis. For SO_2, PM_{10}, and NO_x the table shows i) maximum impacts of Mesaba One and Mesaba Two alone, ii) Mesaba One and Mesaba Two plus local sources that were explicitly included in the five-year model runs, and iii) Mesaba One and Mesaba Two plus all regional sources from FAR modeling of the highest impact days. For CO, no inventory of regional emissions is available. The data in Table 7.7-1 show CO concentrations from Mesaba One and Mesaba Two alone, and conservative total concentration estimates obtained by adding an urban background concentration to Mesaba One and Mesaba Two impacts.

Table 7.7-1 compares total impact estimates to the applicable NAAQS. All predicted concentrations are far below allowable levels and the results demonstrate compliance with all Minnesota and federal ambient air quality standards.

Contours of maximum predicted impacts from Mesaba One and Mesaba Two and nearby sources are shown In the vicinity of the IGCC Power Station in Figures 7.5-7 through 7.7-8. These maps show that the highest impacts (still well below ambient standards) will occur over limited areas in close proximity to the site.

The nearby sources that were included in the five-year NAAQS model runs were:

- Minnesota Power-Clay Boswell Plant (Units 1-4)
- Keewatin Taconite

These major sources are both located within 25 kilometers of the IGCC Power Station Footprint: Minnesota Power to the southwest and Keewatin Taconite to the northeast. In the case of short-term SO_2 impacts, the maximum combined source impacts shown in Table 7.7-1 are primarily due to these nearby sources and occur at locations far from the Mesaba One and Mesaba Two site. The other maximum impact points reflect Mesaba One and Mesaba Two emissions and occur near the site. Details of the locations and times of highest predicted concentrations are included in Appendix D.

Table 7.7-1
Results of Mesaba Class II NAAQS Modeling (Concentrations in $\mu g/m^3$)

Pollutant Averaging Time	Highest [1] Mesaba Alone	Highest[1] Mesaba and Nearby	Highest[1] All Sources	Background	Total	NAAQS
SO2						
1-hour	122.4	322.2	327.4	10	337.4	1300
3-hour	73.4	134.4	136.5	10	146.5	915
24-hour	22.1	30.6	41.4	10	51.4	365
annual	1.29	1.99	2.67	2	4.67	60
PM10	13.3					
24-hour	11.0	13.7	15.8	20	35.8	150
Annual	1.59	1.95	3.14	10	13.14	50
NOx						
Annual	2.60	3.18	5.09	5	10.09	100
CO						
1-hour	2669.8	N/A	N/A	7000[2]	9670	40,000

[1]Listed Highest Concentrations are highest second-high for one to 24-hour averaging times except for PM10, which is the highest 6th high from five years. Annual average values are the highest for any year.
[2]Background CO concentrations are very conservative estimates from urban monitors in Minneapolis/St. Paul. No background data exist for the IGCC Power Station area.

Figure 7.7-1 SO_2 1-Hour Highest Second High Impacts (µg/m^3) Mesaba One and Mesaba Two and Nearby Sources

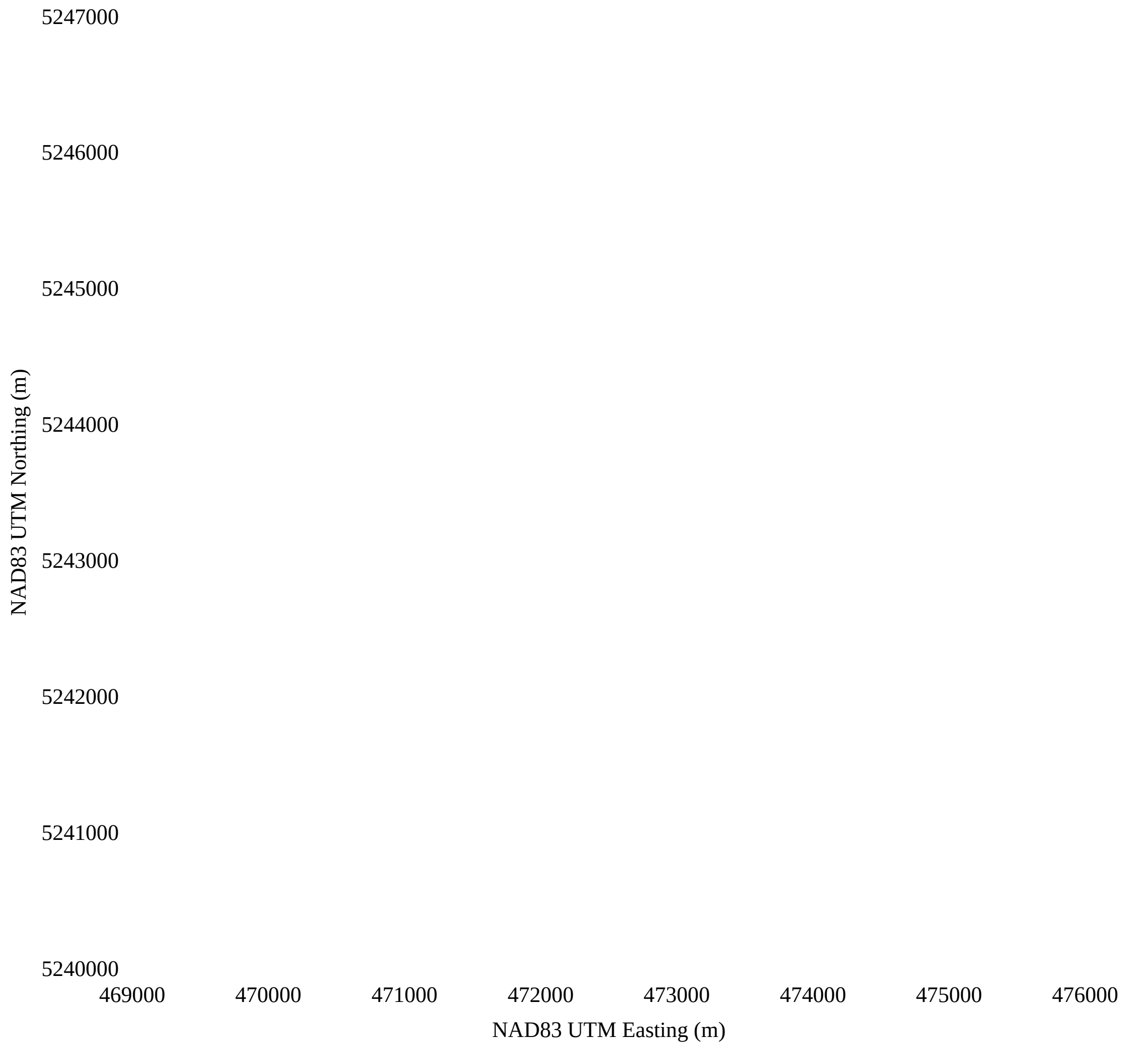

Figure 7.7-1
Figure 42
SO_2 1-Hour Highest Second High Impacts (µg/m^3)
For Mesaba Project Phase I and II and Nearby Sources
Data Year 1975

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Figure 7.7-2. SO_2 3-Hour Highest Second High Impacts ($\mu g/m^3$) Mesaba One and Mesaba Two and Nearby Sources

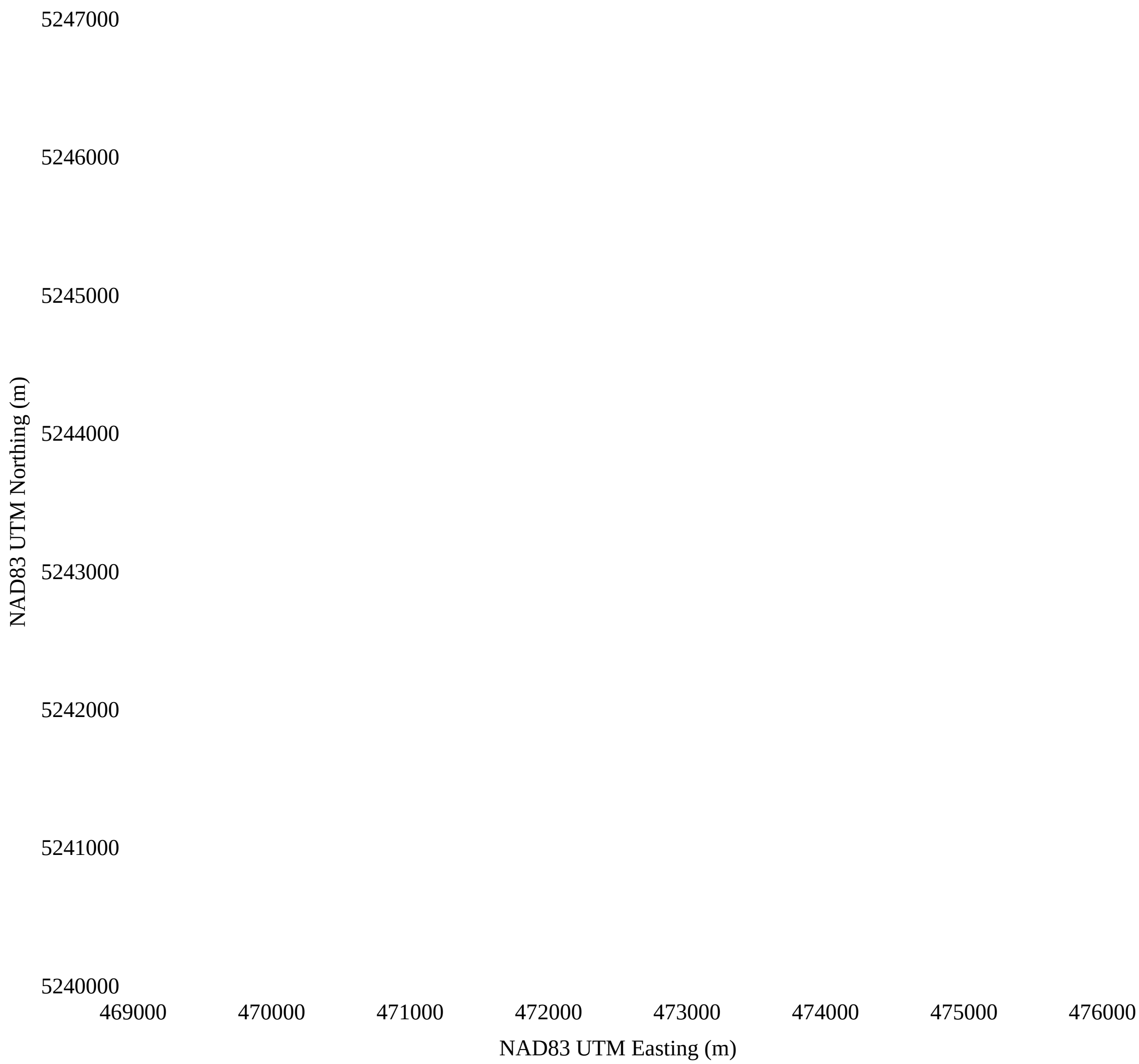

Figure 7.7-2
Figure 43
SO_2 3-Hour Highest Second High Impacts ($\mu g/m^3$)
For Mesaba Project Phase I and II and Nearby Sources
Data Year 1975

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Figure 7.7-3. SO_2 24-Hour Highest Second High Impacts ($\mu g/m^3$) Mesaba One and Mesaba Two and Nearby Sources

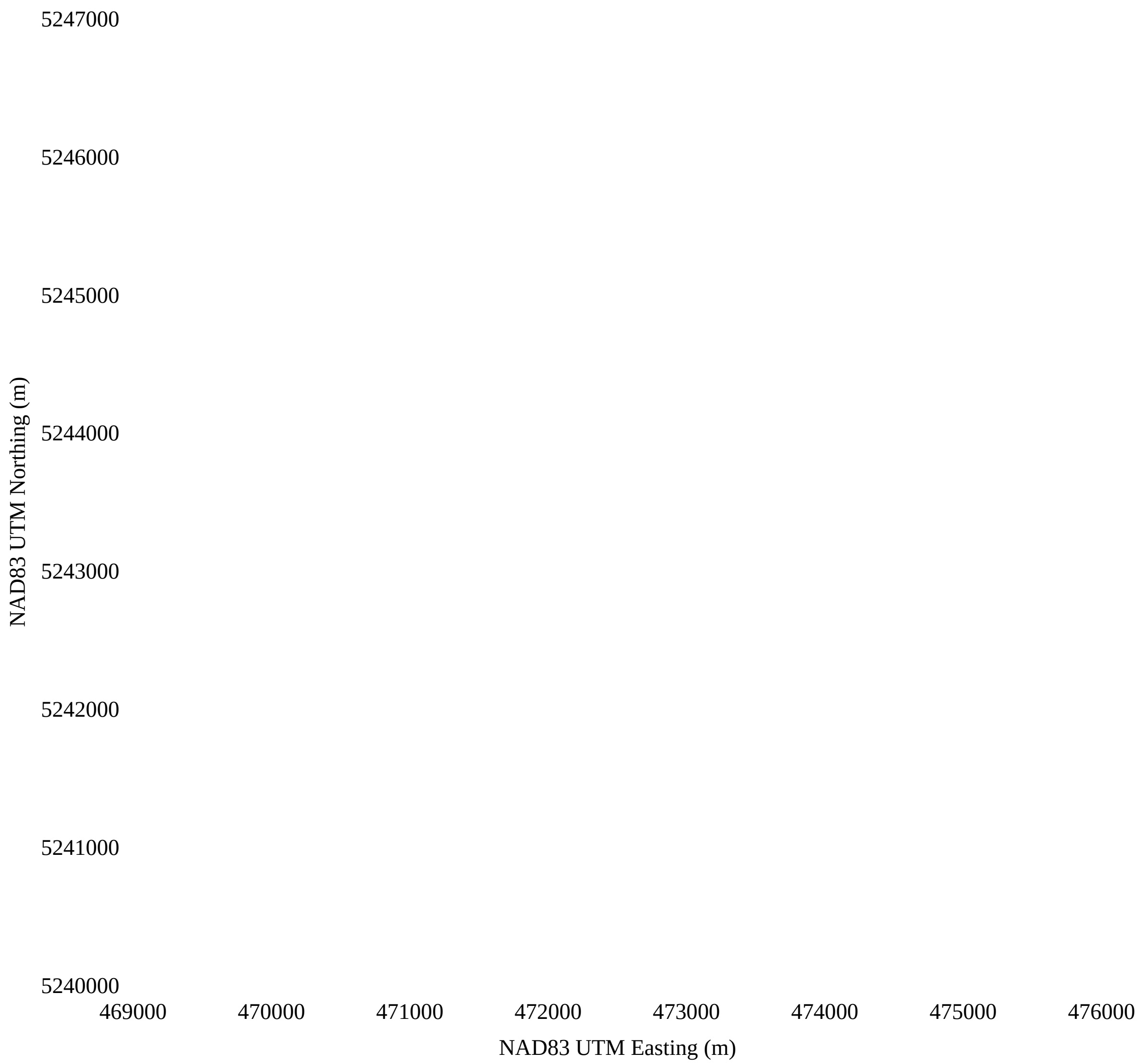

Figure 7.7-3
Figure 44
SO_2 24-Hour Highest Second High Impacts ($\mu g/m^3$)
For Mesaba Project Phase I and II and Nearby Sources
Data Year 1975

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Figure 7.7-4. SO_2 Annual Maximum Impacts (µg/m^3) Mesaba One and Mesaba Two and Nearby Sources

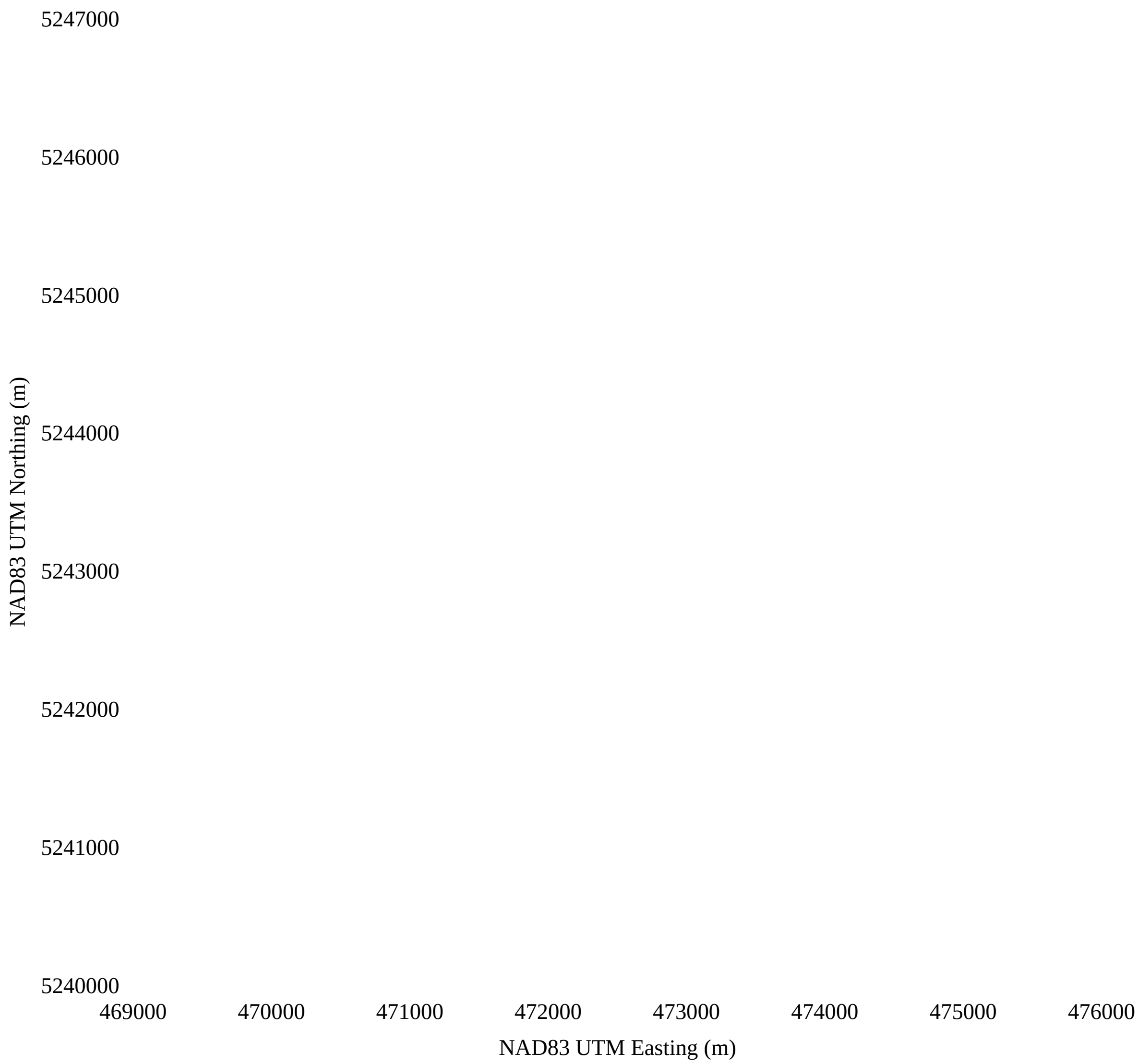

Figure 7.7-4
Figure 45
SO_2 Annual Maximum Impacts (µg/m^3)
For Mesaba Project Phase I and II and Nearby Sources
Data Year 1976